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Transcript Exhibit(s)

G-01551A-04-0876

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To: Docket Control

Re: Southwest Gas Corporation / Rates
Volumes I through VI (CONCLUDED)
October 3 through 11, 2005

STATUS OF ORIGINAL EXHIBITS

FILED WITH DOCKET CONTROL
10-12-2005

STAFF

1 through 23, 26, and 27

SOUTHWEST GAS

1 through 49, and 51

RUCO

1 through 12

ARIZONA COMMUNITY ACTION AGENCY (ACAA)

1

AUIA

1 and 2

SWEEP

1 and 2

DEPARTMENT OF DEFENSE (DOD)

1

EXHIBIT NUMBERS NOT UTILIZED
Numbers skipped or exhibit not used

STAFF

24 and 25

ORIGINAL EXHIBITS RETURNED TO PARTIES

SOUTHWEST GAS

50 Pending

Copy to:

Dwight D. Nodes, ACALJ (letter only)
Staff, Jason Gellman, Esq.
Southwest Gas Corp., Andy Bettwy, Esq.
RUCO, Scott Wakefield, Esq.

Summary of Staff Rate Design in Direct and Supplemental Testimony and Updated for Surrebuttal Revenue Requirement

				Current Rates	Direct Testimony Staff Proposed Rates	Supplemental Testimony Staff Proposed Rates	Updated for Surrebuttal Revenue Requirement Staff Proposed Rates
Rate Schedule G-5, Residential Gas Service							
Median Usage - therms							
Increase in Median Bill From Current to Proposed Rates							
Basic Service Charge				$8.00	$9.50	$9.50	$9.70
Summer	First	20/15	therms	$0.48762	$0.54000	$0.54000	$0.54200
Summer	Over	20/15	therms	$0.40344	$0.49000	$0.49400	$0.50100
Winter	First	40/35	therms	$0.48762	$0.54000	$0.54000	$0.54200
Winter	Over	40/35	therms	$0.40344	$0.49000	$0.49400	$0.50100
Rate Schedule G-10, Low income Residential Gas Service							
Median Usage - therms							
Increase in Median Bill From Current to Proposed Rates							
Basic Service Charge				$7.00	$7.00	$7.00	$7.00
Summer	First	20/15	therms	$0.48762	$0.54000	$0.54000	$0.54200
Summer	Over	20/15	therms	$0.40344	$0.49000	$0.49400	$0.50100
Winter	First	40/35	therms	$0.48762	$0.54000	$0.54000	$0.54200
Winter	Next	110/115	therms	$0.40344	$0.49000	$0.49400	$0.50100
Winter	Over	150	therms	$0.40344	$0.49000	$0.49400	$0.50100
Rate Schedule G-15, Special Residential Gas Service for Air Conditioning							
Median Usage - therms							
Increase in Median Bill From Current to Proposed Rates							
Basic Service Charge				$8.00	$9.50	$9.50	$9.70
Summer	First	20/15	therms	$0.48762	$0.54000	$0.54000	$0.54200
Summer	Over	20/15	therms	$0.19125	$0.28000	$0.28000	$0.28200
Winter	First	40/35	therms	$0.48762	$0.54000	$0.54000	$0.54200
Winter	Over	40/35	therms	$0.40344	$0.49000	$0.49400	$0.50100
Rate Schedule G-20, Master-Metered Mobile Home Park Service							
Median Usage - therms							
Increase in Median Bill From Current to Proposed Rates							
Basic Service Charge				$50.00	$60.00	$60.00	$60.00
Commodity Charge, All Therms				$0.31415	$0.37600	$0.37600	$0.38400
Schedule RGG3-2							
Rate Schedule G-25, General Gas Service, Small							
Median Usage - therms							
Increase in Median Bill From Current to Proposed Rates							
Basic Service Charge				$20.00	$24.00	$24.00	$24.00
Commodity Charge, All therms				$0.38024	$0.44700	$0.44900	$0.45600

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Rate Schedule G-25, General Gas Service, Medium
Median Usage - therms
Increase in Median Bill From Current to Proposed Rates

Basic Service Charge	$90.00	$105.00	$105.00	$105.00
Commodity Charge, All therms	$0.27211	$0.30500	$0.30600	$0.31200

Rate Schedule G-25, General Gas Service, Large
Median Usage - therms
Increase in Median Bill From Current to Proposed Rates

Basic Service Charge	$500.00	$540.00	$540.00	$550.00
Commodity Charge, All therms	$0.08548	$0.10000	$0.10070	$0.10400
Demand Charge	$0.07270	$0.07700	$0.07700	$0.07700

Rate Schedule G-35, Gas Service to Armed Forces
Median Usage - therms
Increase in Median Bill From Current to Proposed Rates

Basic Service Charge	$350.00	$370.00	$370.00	$370.00
Commodity Charge, All therms	$0.18966	$0.21500	$0.21500	$0.22100

Rate Schedule G-40, Air-Conditioning Gas Service
Median Usage - therms
Increase in Median Bill From Current to Proposed Rates

Basic Service Charge, General Service - Small	$20.00	$24.00	$24.00	$24.00
Basic Service Charge, General Service - Medium	$90.00	$105.00	$105.00	$105.00
Basic Service Charge, General Service - Large	$500.00	$540.00	$540.00	$550.00
Basic Service Charge, Essential Agriculture	$75.00	$90.00	$90.00	$90.00
Commodity Charge, All therms	$0.07613	$0.09500	$0.09500	$0.09900

Schedule RGG3-3

Rate Schedule G-45, Street Lighting Gas Service
Median Usage (annual average usage used, see footnote) - therms
Increase in Median Bill From Current to Proposed Rates

Commodity Charge, All therms	$0.47648	$0.54000	$0.54000	$0.54600

Rate Schedule G-55, Gas Service for Compression on Customer's Premises
Median Usage - therms
Increase in Median Bill From Current to Proposed Rates

Basic Service Charge, General Service - Small	$20.00	$24.00	$24.00	$24.00
Basic Service Charge, General Service - Large	$170.00	$185.00	$185.00	$190.00
Basic Service Charge, General Service - Residential	$8.00	$9.50	$9.50	$9.70
Commodity Charge, All therms	$0.13305	$0.16500	$0.16500	$0.17000

Rate Schedule G-60, Cogeneration Gas Service
Median Usage - therms
Increase in Median Bill From Current to Proposed Rates

Basic Service Charge, General Service - Small	$20.00	$24.00	$24.00	$24.00
Basic Service Charge, General Service - Medium	$90.00	$105.00	$105.00	$105.00
Basic Service Charge, General Service - Large	$500.00	$540.00	$540.00	$550.00
Basic Service Charge, Essential Agriculture	$75.00	$90.00	$90.00	$90.00
Commodity Charge, All therms	$0.08934	$0.11000	$0.11000	$0.11400

Rate Schedule G-75, Small Essential Agriculture User Gas Service
Median Usage - therms
Increase in Median Bill From Current to Proposed Rates

Basic Service Charge	$75.00	$90.00	$90.00	$90.00
Commodity Charge, All therms	$0.19468	$0.22000	$0.22000	$0.22300

Rate Schedule G-80, Natural Gas Engine Gas Service
Median Usage - therms
Increase in Median Bill From Current to Proposed Rates

Basic Service Charge, Off-Peak Season (Oct. - Mar)	$0.00	$0.00	$0.00	$0.00
Basic Service Charge, On-Peak Season (Apr - Sep)	$80.00	$95.00	$95.00	$95.00
Commodity Charge, All therms	$0.16189	$0.17600	$0.17600	$0.17700
Cost of Gas	$0.55840	$0.55840	$0.55840	$0.55840

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. G-01551A-04-0876

DIRECT

TESTIMONY

OF

STEVE IRVINE

PUBLIC UTILITIES ANALYST II

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 26, 2005

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EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-04-0876

On December 9, 2004, Southwest Gas Corporation ("Southwest") filed an application with the Arizona Corporation Commission ("Commission") for an increase in its rates throughout the State of Arizona. The application seeks among other things approval for its proposed Demand Side Management ("DSM") programs. Southwest proposed continuation of two existing DSM programs and implementation of seven new DSM programs. Southwest proposes specific funding levels for each program that collectively total $4,385,000.

As Southwest has provided only brief descriptions of the proposed programs, Staff recommends that Southwest submit within 120 days of a decision in this matter to the Commission for approval a DSM plan that includes detailed descriptions of each of the proposed DSM programs. Staff recommends the filing include responses to specific criteria described by Staff in this testimony. Staff recommends that the DSM plan be filed under a new docket number and that for the purposes of compliance verification notice of the filing be made in this docket. Staff recommends approval at this time of a total DSM budget of $4,335,000.

Staff further recommends that the DSM adjustor mechanism be used to fund the newly proposed programs and that future filings for changes to the DSM adjustor level seek Commission approval rather than Staff approval. Staff also recommends that the DSM adjustor be applied to all rate classes.

Finally Staff recommends that semi-annual DSM Progress Reports shall be certified by an Officer of the Company and its existing filing practices shall continue.

INTRODUCTION

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

A. My name is Steve Irvine. I am a Public Utilities Analyst II employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst.

A. In my capacity as a Public Utilities Analyst, I review monthly filings of purchased power adjustors and purchased gas adjustors. My duties also include processing of applications for rate increases, adjustor credits and surcharges, borderline agreements, tariff compliance filings, and various applications of other types.

Q. Please describe your educational background and professional experience.

A. In 1994, I graduated from Arizona State University, receiving a Bachelor of Science degree in Business Marketing. In 1997, I received a Masters degree in Public Administration from Arizona State University. I have been employed by the Commission since May of 2001. I have worked in the Utilities Division since September of 2002.

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket No. G-01551A-04-0876?

A. Yes.

Q. What is the scope of your testimony in this case?

A. My testimony will present Staff's evaluation of Southwest Gas Corporation's ("Southwest") proposal for its Demand Side Management ("DSM") programs.

Q. Will your testimony include discussion of Southwest's proposal for a Conservation Margin Tracker?

A. No. The Conservation Margin Tracker will be addressed in the testimony of Staff witness William Musgrove.

Q. Please provide a brief history of Southwest's DSM programs.

A. Prior to Decision No. 60352 of August 29, 1997, Southwest was divided into two divisions in Arizona, the Southern and Central Division. Decision No. 60352 consolidated the divisions. Prior to consolidation the Southern Division had the Southern Arizona Seniors program and the Energy Advantage Plus Program. The Central Division had a low income weatherization program and the Energy Advantage Home program. These programs involved weatherization repairs or upgrades to existing homes and improvements to the construction of new homes to improve energy efficiency. Prior to Decision No. 60352 the costs for these programs were recovered in rate base. Decision No. 60352 created a DSM Adjustor Mechanism for cost recovery of DSM projects. That Decision also required that all future DSM programs be filed for Staff pre-approval and capped DSM expenditures at $1,000,000. Additionally, it extended semi-annual reporting requirements for all the DSM programs; previously only the Southern Division DSM programs had reporting requirements. The DSM program cap was raised subsequently to $1,125,000 and later $1,250,000 to accommodate funding for a Low Income Energy Conservation program and increased spending in the Seniors program.

CURRENT PROGRAMS

Q. What DSM programs does Southwest currently have?

A. Currently Southwest has two Demand Side Management programs. Both programs are meant to improve energy performance in residential housing and consequently reduce customer bills. The programs are Low-Income Energy Conservation ("LIEC") and Energy Advantage Plus ("EAP").

Q. Please describe the LIEC program.

A. The LIEC program is designed for low income customers. Customers with a household income up to 125 percent of the Federal poverty guideline are eligible for the program. The program provides weatherization improvements and repairs to increase energy efficiency for homes of eligible customers. Multi-family housing projects are also eligible for LIEC program benefits. The LIEC program is administered through the Arizona Department of Commerce - Energy Office ("Energy Office") as part of the Energy Office's broader low income weatherization activities. The Energy Office administers its program with funds provided by Southwest, Federal funding, and funding from other sources. The Energy Office contracts with local community agencies for implementation of the weatherization measures. The program is beneficial as the repairs and improvements made to the homes increase energy efficiency and results in lower bills for the residents. These same efficiencies reduce the system load.

Q. Please describe the EAP program.

A. The EAP program is designed to improve energy performance in new residential homes. The program promotes to builders and homebuyers energy efficiency through improvements to a home's thermal shell and use of high efficiency equipment such as furnaces and other heating appliances. In the past, a portion of the EAP funds were used to advertise the program and offer incentives to builders to participate. Decision No. 67878 of June 2005 reduced funding for the EAP program from $900,000 to $250,000 to reflect elimination of the advertising and builder incentive portion of the program. Southwest no longer views incentives and advertising as necessary given the extent of builder's current participation in the program. The program is beneficial as it promotes the design and construction of homes that are more energy efficient than homes that would have been built otherwise. The increased energy efficiency that results from the program reduces customers' bills and system load.

COST RECOVERY MECHANISM AND REPORTING

Q. Please describe Southwest's current cost recovery mechanism for DSM.

A. Costs for the current DSM programs are recovered through an adjustor mechanism. The adjustor mechanism was approved in Decision No. 60352 of August 1997. Most recently the adjustor was reset on March 23, 2005, to a credit of $0.00054. Southwest currently submits proposals for changes to the adjustor level yearly for Staff approval.

Q. Does Staff have recommendations regarding approval of changes to the DSM adjustor?

A. Yes. Southwest has proposed that the number of DSM programs increase from two to nine and has proposed increasing DSM funding from its current $600,000 level to $4,385,000. These represent significant increases in Southwest's DSM efforts. Accordingly, Staff recommends that in the future proposed changes to the DSM adjustor level be filed for Commission approval.

Q. In addition to proposals for changes to the adjustor mechanism, does Southwest submit other reports related to its DSM program?

A. Yes. Southwest currently submits a semi-annual Demand Side Management Progress Report. A redacted version is filed in Docket Control and a confidential version is submitted to Staff. The report details information such as budget, costs, and program activities. In order to encourage accuracy in reporting, Staff recommends that in the future the semi-annual DSM Progress Reports be certified by an Officer of the Company and that existing filing practices continue.

Q. Is the existing DSM adjustor an appropriate mechanism to fund costs for the new DSM programs that Southwest has proposed?

A. Yes. The current DSM adjustor is an appropriate mechanism to fund the new DSM programs that Southwest has proposed. The current DSM adjustor is already in place and would serve as a single consolidated mechanism for recovery of the DSM costs. Staff recommends that the existing DSM adjustor be used to fund all of Southwest's DSM programs, including new programs that may be adopted.

Q. Does Staff have additional recommendations regarding the DSM recovery mechanism?

A. Yes. In the past DSM costs have only been recovered from residential customers. Now that new programs are being proposed for commercial and industrial customers Southwest proposes that the DSM adjustor be recovered from all customer classes. Staff agrees that with approval of the new DSM programs it would be appropriate to recover the DSM adjustor cost from each of the rate classes. Consequently, Staff recommends that Southwest's DSM adjustor be applied to all of Southwest's customer classes.

PROPOSED PROGRAMS

Q. What are the new DSM programs that Southwest is proposing?

A. Southwest has proposed the following new residential programs: Multi-Family New Construction, Residential Energy Conservation, and Energy Star® Appliances. Southwest has proposed the following new Commercial and Industrial programs: Food Service Equipment, Efficient Commercial Building Design, Technology Information Center, and Distributed Generation.

Q. Please describe the Multi-Family New Construction program as it is proposed.

A. The Multi-Family New Construction program is designed to provide to renters and condominium owners benefits similar to those provided in the EAP program. Much as it does in the EAP program, Southwest will work with designers and developers of multi-family new construction primarily in Maricopa and Pima Counties to improve the energy efficiency of multi-family residences. Improvements will be achieved through upgrades to more efficient appliances and improvements to the building envelope. The program is designed to reduce customers' bills and system load much as it does in the EAP program.

Q. Please describe the Residential Energy Conservation Program as it is proposed.

A. The Residential Energy Conservation program will provide education and incentives to those who wish to undertake energy-saving measures in their homes. Southwest will promote in-store training at home improvement stores to teach weatherization techniques such as installation of insulation, weatherstripping, and caulking. The program will also offer rebates on selected energy efficiency products to promote their use. The program promotes energy efficiency to homeowners who may not be eligible for participation in the LIEC program, EAP program, or Multi-Family New Construction program. The goals are to help homeowners improve the energy efficiency of their own homes consequently reducing their bills and system load.

Q. Please describe the Energy Star® Appliance program as it is proposed.

A. The Energy Star® Appliance program will promote purchases of high-efficiency appliances such as furnaces, water heaters, and washing machines. Southwest will promote the products through provision of educational materials at the point of purchase, training of retailers, and price incentives for selected appliances. The program is meant to increase the use of more energy efficient appliances. The program benefits any individual or organization that purchases Energy Star® Appliances. Use of these appliances will result in energy cost savings for the users and reduced system load.

Q. Please describe the Food Service Equipment Program as it is proposed.

A. The Food Service Equipment program will promote efficiencies in restaurants and commercial food service facilities. Southwest will provide information regarding high-efficiency equipment used in food service through training at its Food Service Center in Tempe and through other informational material. Rebates will be offered for high-efficiency natural gas appliances such as water booster heaters for dishwashers, gas cooking appliances, energy-efficient washing equipment, and high-efficiency hot water heaters. The program is meant to increase heating efficiency in a number of food service processes. These heating efficiencies will result in lower operating costs for food service providers and reduce load on Southwest's gas system.

Q. Please describe the Efficient Commercial Building Design program as it is proposed.

A. The Efficient Commercial Building Design program promotes energy-saving measures in the design and construction of new commercial buildings. This is achieved by providing professionals involved in the design of new buildings with educational materials and workshops which provide instruction on improved construction techniques, building materials, and energy-efficient equipment. Financial incentives will also be provided to encourage participation. The program is meant to result in the construction of more energy efficient commercial buildings. Improvements in the energy performance of commercial buildings will result in cost savings for the buildings' owners or operators and reduced system load.

Q. Please describe the Technology Information Center program as it is proposed.

A. The Technology Information Center program will serve as an informational resource for industrial and commercial customers. The center will provide information related to energy-efficiency through a variety of media such as a call center, newsletters, and the internet. The program is meant to provide technical instruction to a variety of commercial and industrial customers. Many of these customers will be owners or operators of existing commercial and industrial facilities and are not eligible for the benefits of the Efficient Commercial Building Design program.

Q. Please describe the Distributed Generation program as it is proposed.

A. The Distributed Generation program encourages projects that demonstrate either combined heat and power or peak-shaving concepts in industrial applications. It is difficult to evaluate how such a program would benefit in management of gas load vs. electric load until further detail about the program is developed. Staff has approved of distributed generation as a DSM program for both gas and electric utilities in Staff's First Draft of Proposed DSM Rules – April 15, 2005, and will give further consideration to Southwest's proposal in this matter when details of the program are filed.

FUNDING LEVELS AND APPROVAL

Q. What are the funding levels of Southwest's current DSM programs?

A. Funding levels for Southwest's current DSM programs are shown in Table I below.

Table I
CURRENT FUNDING LEVELS

Low Income Energy Conservation *(Residential)*	$350,000
Energy Advantage Plus *(Residential)*	$250,000

Q. What are the funding levels that Southwest proposes for its new DSM programs?

A. Funding levels that Southwest proposes for its new DSM programs are shown in Table II below.

Table II
FUNDING LEVELS PROPOSED BY SOUTHWEST

Low Income Energy Conservation *(Residential)*	$500,000
Energy Advantage Plus *(Residential)*	$250,000
Multi-Family New Construction *(Residential)*	$1,200,000
Residential Energy Conservation *(Residential)*	$200,000
Energy Star® Appliances *(Residential)*	$800,000
Food Service Equipment *(Commercial and Industrial)*	$500,000
Efficient Commercial Building Design *(Commercial and Industrial)*	$500,000
Technology Information Center *(Commercial and Industrial)*	$35,000
Distributed Generation *(Commercial and Industrial)*	$400,000

Q. Please comment on these proposed funding levels.

A. Southwest has included brief descriptions of its newly proposed programs in its direct testimony. Southwest has not included in its proposal detailed descriptions of the new programs or cost benefit analyses of the programs. At this time Staff does not have sufficient information regarding each of the newly proposed programs to make recommendations regarding funding levels for each of the programs. Staff finds Southwest's proposal reasonable as a whole, but cannot make specific recommendations regarding each new program until more specific information is provided.

Q. What recommendations does Staff have regarding funding of Southwest's DSM programs?

A. In order to allow consideration of the proposed programs in an informed manner, Staff recommends that within 120 days of a decision in this matter Southwest submit to the Commission for approval a DSM plan that includes detailed descriptions of each of the proposed DSM programs. Staff recommends that the DSM plan be filed under a new docket number and that for purposes of compliance verification notice of the filing be made in this docket.

Q. What information should Southwest be required to provide when it submits its DSM program for approval?

A. The following is a list of DSM evaluation topics that Southwest should be required to provide:

1. Description of the program.
2. Objectives and rationale for the program.
3. Market segment at which the program is aimed, including geographic limitations.
4. Estimated level of program participation.
5. Estimate of baseline (when applicable).
6. Estimated societal benefits and savings from the program.
7. Estimated societal costs of the programs.
8. Marketing and delivery strategy.
9. Utility costs and budget.
10. Implementation schedule.
11. Monitoring and evaluation plan.
12. Proposed performance incentives.

Q. How will this information help in consideration of program approval?

A. This information, among other things, will help in describing the nature of the programs, their goals, who they may benefit, what benefits they may provide, how the program will be measured, and whether benefits can be expected.

Q. Does Staff's recommendation that within 120 days of a decision in this matter Southwest submit to the Commission for approval a DSM plan that includes detailed descriptions of each of the proposed DSM programs include submitting for consideration the existing EAP and LIEC programs?

A. Yes. While these programs have been approved in the past, Staff finds that it will be beneficial to include these programs when considering Southwest's entire DSM program. Inclusion of these existing programs in Southwest's filing for approval will allow the Commission to consider the funding levels of each of the proposed DSM programs concurrently. This will facilitate reallocation of funding among the various programs should the Commission choose to do so. Additionally, it will allow the Commission to consider funding for the EAP and LIEC programs in light of the most recent analysis of the programs available.

Q. What should be the status of the existing EAP and LIEC programs while the Commission is considering Southwest's entire DSM program?

A. In order to provide continuity of benefits, Staff recommends that the EAP and LIEC programs continue as previously approved and at their current funding levels until the Commission examines the detailed plans for the DSM programs and issues a decision in the matter.

Q. What other recommendations does Staff have regarding funding of Southwest's DSM programs?

A. The new programs and funding levels greatly increase Southwest's DSM efforts. Staff recommends approval of the total combined funding level at this time as proposed by Southwest with the exception of a reduction related to the spending proposed for bill assistance as a component of the LIEC program.

Q. Please describe the basis for Staff's exception to Southwest's proposal for bill assistance as a component of the LIEC program.

A. Southwest has proposed that $50,000 of LIEC funds be used annually for customer bill assistance. In response to a data request from Staff on the matter Southwest has indicated it has had discussions with Arizona community service organizations regarding the possibility of their administration of the bill assistance program. Exactly who might administer the program is not yet formally established. Southwest currently has a Low Income Rate Assistance program ("LIRA") which provides a 20 percent discount on the commodity portion of the winter bills of eligible customers. While the LIRA program exists to provide rate assistance, currently no rate assistance is provided to Southwest customers through third parties. Consequently, Southwest's proposal for $50,000 in spending for rate assistance administered through the third parties would be a new rate assistance program for Southwest. Southwest has not included in its application details about how such a program would operate. Most significantly, the proposed program is a rate assistance program and is not a DSM program. Staff recommends that the Commission not approve Southwest's request to include $50,000 in rate assistance as a part of its DSM program. As Staff is not recommending approval of the rate assistance portion of Southwest's DSM proposal, Staff recommends that Southwest's proposal for total DSM spending be reduced by $50,000.

Q. What DSM funding level is Staff recommending for Southwest?

A. Staff recommends that Southwest's total annual DSM budget be $4,335,000.

Q. What effects would the cost of the new programs have on customer bills?

A. The average monthly use of Southwest's residential customers in the test year was 29 therms. The new DSM program recommendations, excluding the proposed $50,000 spending for bill assistance within the LIEC program, will result in costs of $0.2075 per average monthly residential bill. This is an increase of $0.0628 monthly over the DSM program costs for average residential customers during the test year. While the DSM costs at either Southwest's or Staff's recommended funding level are a significant increase over the existing funding level, the impact of the funding increase is reduced as DSM costs will be recovered from all customer classes rather than only from residential customers as was done previously. In the 2004 test year, average residential customer therm use in January was 72 therms. The new DSM program recommendations, again excluding the proposed $50,000 spending for bill assistance within the LIEC program, will result in costs of $0.5152 per bill at the 72 therm use level. This is an increase in January of $0.1559 over the DSM program costs for residential customers during the test year.

The monthly increase in DSM cost to residential customers at various therm levels is demonstrated in Table III and Table IV. Both tables demonstrate DSM costs that result from implementation of Staff's proposed $4,335,000 program funding level. These costs are compared to the Test Year DSM Cost of $0.00499 per therm monthly. Table III makes a comparison based on average and median residential therm use in January of the test year. A January comparison is made as January is typically the peak therm use month. Table IV makes a comparison based on average monthly and median monthly residential therm use from the entire test year.

Table III
DSM COSTS
January Therm Use

	Therm Level	Test Year DSM Cost	DSM Cost Given Staff's Proposed DSM Funding Level	Difference
Low Use Customer 50% of average	36	$0.1796	$0.2576	$0.0780
Median Use Customer	58	$0.2894	$0.4151	$0.1257
Average Use Customer	72	$0.3593	$0.5152	$0.1559
High Use Customer 150% of average	108	$0.5389	$0.7729	$0.2340

Table IV
DSM COSTS
Monthly Average and Median Therm Use

	Therm Level	Test Year DSM Cost	DSM Cost Given Staff's Proposed DSM Funding Level	Difference
Low Use Customer 50% of average	15	$0.0724	$0.1038	$0.0314
Median Use Customer	16	$0.0798	$0.1145	$0.0347
Average Use Customer	29	$0.1447	$0.2075	$0.0628
High Use Customer 150% of average	44	$0.2171	$0.3113	$0.0942

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please provide a summary of each of Staff's recommendations regarding DSM.

A. Staffs recommendations are as follows:

1. Proposed changes to the DSM adjustor level shall be filed for Commission approval.
2. Future semi-annual DSM Progress Reports shall be certified by an Officer of the Company and its existing filing practices shall continue.
3. The existing DSM adjustor shall be used to fund all of Southwest's DSM programs, including new programs that may be adopted.
4. Southwest's DSM adjustor shall be applied to all of Southwest's customer classes.
5. Within 120 days of a decision in this matter Southwest shall submit to the Commission for approval a DSM plan that includes detailed descriptions of each of the proposed DSM programs.
6. The DSM plan shall be filed under a new docket number.
7. Notice of filing of the DSM plan shall be made in this docket.
8. Southwest shall provide in its DSM plan, at a minimum, an evaluation of each of the proposed programs using the twelve DSM evaluation topics discussed in this report.
9. The EAP and LIEC programs shall continue as previously approved and at their current funding levels until the Commission examines the detailed plans for the DSM programs and issues a decision in the matter.
10. Southwest's total annual DSM budget should be established at $4,335,000.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	)	DOCKET NO. G-01551A-04-0876

SURREBUTTAL

TESTIMONY

OF

STEVE IRVINE

PUBLIC UTILITIES ANALYST III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

SEPTEMBER 13, 2005

EXHIBIT
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EXHIBIT

EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-04-0876

On December 9, 2004, Southwest Gas Corporation ("Southwest") filed an application with the Arizona Corporation Commission ("Commission") for an increase in its rates throughout the State of Arizona. The application seeks among other things approval for its proposed Demand Side Management ("DSM") programs. Southwest proposed continuation of two existing DSM programs and implementation of seven new DSM programs.

On August 23, 2005, Southwest filed Rebuttal Testimony. Having reviewed Southwest's rebuttal testimony, Staff now reasserts recommendations made in Direct Testimony and proposes additional recommendations, including: future semi-annual DSM Progress Reports should be certified by an Officer of the Company; that the Commission evaluate the appropriateness of the bill assistance component of the Low-Income Energy Conservation DSM program as a separate and distinct program from DSM, but that Southwest's request to include $50,000 in rate assistance as a part of its DSM program should not be approved; the total annual DSM budget should be $4,335,000; Southwest should implement and maintain a collaborative DSM working group to solicit and facilitate input from any interested party; finally, implementation of a performance incentive should not be approved.

INTRODUCTION

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

A. My name is Steve Irvine. I am a Public Utilities Analyst III employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Have you filed Direct Testimony in this case?

A. Yes, I have. In Direct Testimony I provided Staff's recommendations regarding Southwest Gas Corporation's ("Southwest" or "Company") proposal for its Demand Side Management ("DSM") programs.

Q. What is the purpose of this Surrebuttal Testimony?

A. This Surrebuttal Testimony addresses matters raised in the Rebuttal Testimony of Southwest witness Vivian E. Scott. The first matter to be addressed is Southwest's recommendations for Progress Reports and Filing Practices. The second matter to be addressed is the Bill Assistance Component of the Low-Income Energy Conservation ("LIEC") program. The third matter to be addressed relates to proposals by Southwest, RUCO, Southwest Energy Efficiency Project ("SWEEP") and Natural Resources Defense Council ("NRDC") regarding Program Approval, Funding, and the Collaborative Process. The final matter which will be addressed is Southwest's comments on a proposal by Sweep/NRDC to include a Performance Incentive.

PROGRESS REPORTS AND FILING PRACTICES

Q. What recommendations has Staff made regarding Progress Reports and Filing Practices?

A. In Direct Testimony, Staff has recommended that Southwest's future semi-annual DSM Progress Reports be certified by an Officer of the Company as indicated in the Annual Report that Southwest submits to the Commission.

Q. Has Staff's recommendation in this matter changed?

A. No. In Rebuttal Testimony (Scott Rebuttal Testimony page 3), Southwest submits that officer certification for these reports is not necessary. Staff continues, however, to recommend a requirement that the reports be certified by an Officer of the Company. A requirement for certification of the reports by an Officer of the Company will create a high level of accountability for the accuracy of the reports. Staff finds a higher level of accountability appropriate given the increased size and monetary costs of the program.

BILL ASSISTANCE COMPONENT OF LOW-INCOME ENERGY CONSERVATION ("LIEC")

Q. What is Staff's recommendation regarding the bill assistance component of the LIEC program.

A. In Direct Testimony (Irvine Direct Testimony page 12), Staff recommends that the Commission not approve Southwest's request to include $50,000 in rate assistance as a part of its LIEC program.

Q. Does Southwest agree with this position?

A. No. In rebuttal testimony (Scott Rebuttal Testimony page 3), Southwest disagrees with Staff's recommendation. Southwest contends that the funds will be used to help low-income customers in emergency situations and cites that a similar program was approved recently for Arizona Public Service Company ("APS").

Q. Does Staff maintain its recommendation that the bill assistance component of the LIEC program not be approved?

A. Yes. While a bill assistance benefit for low-income customers in emergency situations would help needy customers, and a similar program has been approved for APS, it remains that bill assistance is not DSM and consequently not an appropriate component of a DSM program. Inclusion of rate assistance measures within a DSM program would have several undesirable effects. The instrument used to fund DSM programs is a rate component called the DSM adjustor. Its name implies to ratepayers that it is an assessment for DSM costs. Should rate assistance be included in the DSM program, it may not be clear to ratepayers that they also fund rate assistance through the DSM adjustor. Additionally, inclusion of a rate assistance component within a DSM program will result in a lack of clarity related to the total annual level of Southwest's DSM funding. Should rate assistance be included in the DSM program, the actual level of DSM funding could only be accurately described by the total DSM program funding level minus the amount of funds used for the rate assistance component. Finally, inclusion of program components which are not DSM within the DSM program could reduce clarity about the objectives of the DSM program. However, the Commission should evaluate the appropriateness of the bill assistance component of the Low-Income Energy Conservation DSM program as a separate and distinct program from DSM, and Southwest's request to include $50,000 in rate assistance as a part of its DSM program should not be approved.

Q. Why does Staff not recommend inclusion of bill assistance within a DSM program when recently bill assistance was included in a DSM program approved for APS?

A. Decision No. 67744 of April 2005 approved a settlement agreement for APS' rate application. Included in that Decision and settlement agreement was a rate assistance component in APS' DSM program. Many parties with diverse interests participated in the APS settlement agreement. Recommendations made in the settlement agreement were the result of a negotiated process. Taken on its own, and removed from any negotiated process, Staff finds that inclusion of rate assistance as a component of a DSM program inappropriate. However, as stated earlier, the Commission should evaluate the appropriateness of the bill assistance component of the Low-Income Energy Conservation DSM program as a separate and distinct program from DSM, and Southwest's request to include $50,000 in rate assistance as a part of its DSM program should not be approved.

PROGRAM APPROVAL, FUNDING, AND THE COLLABORATIVE PROCESS

Q. What has Staff recommended regarding program approval?

A. Staff has recommended that within 120 days of a decision in this matter Southwest shall submit to the Commission for approval a DSM plan that includes detailed descriptions of each of the proposed DSM programs. Staff has also recommended that the DSM plan shall be filed under a new docket number and that only the total annual DSM budget be approved at this time.

Q. Does Southwest agree with these recommendations?

A. It is unclear what position Southwest takes regarding program approval. On page 5 of Rebuttal Testimony of Southwest's witness Vivian E. Scott, Southwest recommends both approval of the proposed programs at this time and final Commission approval within 120 days. It is not clear what conditions Southwest intends to establish through approval of the programs at this time relative to final approval within 120 days.

Q. Given Southwest's position, what does Staff recommend regarding program approval.

A. Staff continues to recommend that within 120 days of a decision in this matter Southwest shall submit to the Commission for approval a DSM plan that includes detailed descriptions of each of the proposed DSM programs. The filing shall be made under a new docket number and only the total proposed funding level be approved at this time.

Q. What has Staff recommended regarding funding approval?

A. Staff has recommended a total annual DSM budget of $4,335,000. This figure is based on Southwest's original budget proposal, but having eliminated funding for the bill assistance component of the LIEC program.

Q. Does Southwest agree with Staff's recommendation regarding the funding level?

A. No. Southwest's witness Vivian E. Scott describes in Rebuttal Testimony that Southwest requests a funding level sufficient to fund an expanded Energy Star® Home Certification program and performance incentives proposed in testimony of SWEEP/NRDC (Scott Rebuttal Testimony page 5).

Q. What recommendation has SWEEP/NRDC made regarding an expanded Energy Star® Home Certification program?

A. SWEEP/NRDC has recommended that funding for the Energy Star® Home Certification program, currently called the Energy Advantage Plus program ("EAP"), be increased from the proposed $250,000 to at least $1,000,000. SWEEP/NRDC cites that such funding is necessary in order to provide the program throughout the Southwest Gas service territory and for promoting and incentivizing the program (page 5 of Direct Testimony of Jeff Schlagel).

Q. **What are Staff's comments regarding additional Energy Star® Home Certification program funding for promotions and incentives?**

A. On page 4 of Direct Testimony of Southwest's witness Vivian E. Scott, Ms. Scott describes that as a result of past efforts, Southwest now believes that the market has sufficiently transformed and that incentives are no longer necessary to ensure more energy-efficient construction. Southwest also cited this belief in its application May 10, 2005 for continuation of the Energy Advantage Plus Program (Docket No. G-01551A-05-0249). Consequently, in Decision No. 67878 of June 1, 2005, the Commission ordered that the annual EAP budget be reduced from $900,000 to $250,000.

Q. **What are Staff's comments regarding additional funding for the Energy Star® Home Certification program in order to provide the program throughout the Southwest Gas service territory?**

A. In a data request to Southwest, Staff inquired about the extent to which Southwest would be able to offer each of the proposed DSM programs through its service territory. In response to this request (Southwest's response to STAFF-SPI-16 question #3, See Exhibit SPI-1), Southwest indicated that it expected that the Energy Star® Home Certification program could be offered throughout its entire service area. Southwest responded to this data request following its Direct Testimony recommendation in which it recommended a funding level of $250,000, and prior to the recommendation by SWEEP/NRDC that the program level be increased to at least $1,000,000. Southwest's expectation that the program can be offered throughout its service territory when funded at the $250,000 level does not support the recommendation by SWEEP/NRDC to increase the program funding for purposes of expansion of the program to the entire service territory.

Q. What is Staff's recommendation regarding the proposal that the Energy Star® Home Certification program funding level be increased from $250,000 to $1,000,000?

A. Given that Southwest and Staff believe it is no longer necessary to provide program incentives or to promote the program, and given Southwest's expectation that it could offer the program throughout its entire service area, Staff does not support the recommendation to increase funding of the Energy Star® Home Certification program beyond the $250,000 level previously proposed by both Southwest and Staff. For this reason, Staff continues to recommend a total annual DSM budget level of $4,335,000, which includes $250,000 for the Energy Star® Home Certification program.

Q. What are Staff's comments regarding use of a collaborative process to consider Southwest's formal DSM program proposal?

A. In Direct Testimony, Staff recommended that Southwest file for Commission approval an application under a new docket number with detailed plans for the DSM programs. RUCO and SWEEP/NRDC have proposed that a working group be formed to consider the DSM proposal and any member of the group be permitted to submit a program plan to the Commission for approval. Southwest supports the collaborative process as a means to obtain input from participants, but takes exception to the proposal that any member of the group be permitted to submit a program plan to the Commission for approval (Scott Rebuttal Testimony page 5). Staff agrees that formation of a working group will allow for consideration of input of interested parties and recommends that such a group be formed. Staff recommends that Southwest be required to implement and maintain the collaborative DSM working group to solicit and facilitate input from any interested party. The DSM working group shall review Southwest's draft program plans before Southwest submits them to the Commission. Southwest shall retain responsibility for demonstrating to the Commission the appropriateness of any program proposed by Southwest.

Q. Does Staff have comments related to the ability of parties to submit their own proposals for a DSM program for consideration by the Commission?

A. Staff notes that once Southwest's DSM proposal is filed under a new docket number, any interested party is permitted to file for intervention and submit comments in the matter. Such comments could include alternative proposals.

PROPOSAL BY SWEEP/NRDC TO INCLUDE A PERFORMANCE INCENTIVE

Q. What has Staff recommended regarding a performance incentive?

A. Staff has not made a recommendation regarding a performance incentive in Direct Testimony. Southwest had not made a recommendation for a performance incentive in Direct Testimony. A recommendation for a performance incentive was introduced in Direct Testimony of Jeff Schlegel, representing SWEEP/NRDC. Southwest supports the performance incentive recommendation in Rebuttal Testimony of Southwest witness Vivian E. Scott.

Q. What comments does Staff have at this time regarding a performance incentive?

A. It is not clear in either Direct Testimony of Jeff Schlegel or Direct Testimony of Vivian E. Scott how the amount of any performance incentive would be calculated. The recommendation does describe that the incentive should be based on net economic benefits and metrics such as number of customers served. SWEEP/NRDC also describes that the incentive mechanism should include a threshold for minimum performance. It is Staff's expectation that setting a minimum performance threshold is unnecessary as

Southwest would implement any programs as ordered by the Commission regardless of whether a performance incentive exists or not. Additionally, it is unclear to Staff how Southwest's effort to implement the programs would be reduced should it not be granted a performance incentive. For this reason Staff does not recommend implementation of a performance incentive.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please provide a summary of each of Staff's recommendations regarding DSM made in this testimony.

A. Staffs recommendations are as follows:

1. Future semi-annual DSM Progress Reports shall be certified by an Officer of the Company.
2. The Commission should evaluate the appropriateness of the bill assistance component of the Low-Income Energy Conservation DSM program as a separate and distinct program from DSM, and Southwest's request to include $50,000 in rate assistance as a part of its DSM program not be approved.
3. Within 120 days of a decision in this matter, Southwest shall docket for the Commission's approval a DSM plan that includes detailed descriptions of each of the proposed DSM programs. This application for approval of the DSM Plan shall be made under a new docket number and only the total proposed funding level shall be approved at this time.
4. Approval of a total annual DSM budget of $4,335,000.
5. Southwest be required to implement and maintain the collaborative DSM working group to solicit and facilitate input from any interested party.
6. The DSM working group shall review Southwest's draft program plans before Southwest submits them to the Commission.

7. Southwest shall retain responsibility for demonstrating to the Commission the appropriateness of any program proposed by Southwest.

8. The Commission shall not approve implementation of a performance incentive.

Q. Does this conclude your testimony?

A. Yes it does.

EXHIBIT SPI-1

SOUTHWEST GAS CORPORATION
2004 ARIZONA GENERAL RATE CASE
* * *

ACC LEGAL DIVISION DATA REQUEST NO. 16
SWG'S DATA REQUEST NO. STAFF-SPI-16
(STAFF-SPI-16-1 THROUGH STAFF-SPI-16-8)

DOCKET NO.:	G-01551A-04-0876
COMMISSION:	ARIZONA CORPORATION COMMISSION
DATE OF REQUEST:	JUNE 15, 2005

Request No. STAFF-SPI-16-3:

Please describe the extent to which Southwest Gas anticipates it will be able to extend benefits of each of the 9 conservation and energy efficiency programs to its entire service territory. If Southwest Gas anticipates that any of the 9 programs benefits cannot be extended to its entire service area, then please precisely describe both the limited geographic area that Southwest Gas anticipates will be served, and the conditions or funding levels required to extend the benefit(s) to its entire service area.

Respondent: Conservation & Demand Side Management

Response:

The extent to which Southwest anticipates that it will be able to extend the benefits for each of its nine proposed conservation and energy efficiency programs to its entire service territory is described below, by program.

Low-Income Energy Conservation

Southwest expects to be able to offer this program throughout its entire service area.

Energy Star Home Certification

Southwest expects to be able to offer this program throughout its entire service area.

Multi-Family New Construction

This program is available for all geographic areas. However, because the nature of the program is multi-family new construction and because the bulk of such con-

(Continued on page 2)

Response to Request No. STAFF-SPI-16-3: (continued)

struction will most likely occur in the two major metropolitan areas in Arizona, Southwest expects to focus this program primarily in Maricopa and Pima counties.

Residential Energy Conservation

Southwest expects to be able to offer this program throughout its entire service area.

Energy Star Appliances

Southwest expects to be able to offer this program throughout its entire service area.

Food Service Equipment

Southwest expects to be able to offer this program throughout its entire service area.

Efficient Commercial Building Design

Southwest expects to be able to offer this program throughout its entire service area.

Technology Information Center

Southwest expects to be able to offer this program throughout its entire service area.

Distributed Generation

There are no geographic limitations on this program. However, the proposed funding amount will likely limit the number of applications. At this time, Southwest does not know where the actual equipment installations may occur.

ARK F... DI... SECRETARY ... COMM.

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ARKANSAS PUBLIC SERVICE COMMISSION

FILED

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.

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[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.

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AGC filed the written testimonies of Denise E. Baker, and Christopher A. John. CEUG filed the written testimonies of Steven A. Ward, and Timothy P. Staley.

PUBLIC HEARINGS

A Public evidentiary hearing was held in Little Rock, Arkansas, on August 9-12, 2005, for the purpose of receiving public comments, opening statements, and litigating the issues contested by the parties in this proceeding. Additional public comment hearings were conducted at various locations within Arkla's service territory: on August 19, 2005, in Monticello, AR, on August 23, 2005, in Jonesboro, AR, August 25, 2005, in Brinkley, AR, on August 26, 2005, in Texarkana, AR, and on August 30, 2005, in Russellville, AR.

TEST YEAR

Arkla's Application in this proceeding is based on a test year ended April 30, 2004 which utilized 12 months of historical data, as adjusted for known and measurable changes for the *pro forma* year ended April 30, 2005.

POSITIONS OF THE PARTIES

Arkla's sur-surrebuttal case, filed on July 22, 2005, revised Arkla's non-gas revenue deficiency to $27,938,538[3] based on an overall non-gas revenue requirement of $178,859,792. Also, Arkla proposed: to use a lead lag study ("LLS") rather than the Modified Balance Sheet Approach ("MBSA") to determine the amount of cash working capital to include in rate base; to increase the residential customer charge from $9.75 to $17.00; to provide a Voluntary Fixed Price Option ("VFPO") which would allow qualifying customers to fix the cost of their gas supply; and to terminate its Rural Extension Fund ("REF") by contributing those funds to Arkla's Good Neighbor Fund, and the Arkansas Weatherization Assistance Program. Arkla also proposed various riders, including: (1) a Load Change Adjustment ("LCA"), which would provide margin recovery due to the decline in customers and the decline in average use per customer; (2) an Infrastructure Cost Recovery Rider ("ICR"), which provides for the recovery of the cost of capital related to certain non-revenue producing capital investments in natural gas facilities and certain operating expenses; and (3) if the Commission chooses not to adopt the LCA and/or ICR, a Rate Stabilization Plan which would adjust Arkla's rates or credit customer bills annually to reflect changes in costs and revenues.

In its Surrebuttal case, the Staff determined that Arkla has a revenue excess of \$12,714,105 and a non-gas revenue requirement of \$138,207,149. Major differences between the Arkla and Staff case positions include: plant-in-service, working capital assets; rate of return; depreciation expense; employee wages; salaries and compensation; the cash balance benefit and restoration plan expense; and cost allocation and rate design. The Staff opposes all of Arkla's proposed riders, the VFPO, and the manner in which the termination of the REF is treated.

Neither the AG, AGC, nor CEUG addressed all aspects of Arkla's rate case filing. The AG addressed some rate base and expense issues, rate of return, cost allocation and rate design, and Arkla's rate rider proposals. The AGC made recommendations which concerned cost allocation and rate design, cash working capital, various tariff issues, and Arkla's proposed riders. The CEUG made recommendations to the Commission concerning cost allocation and

[3] On August 4, 2005, the Commission issued Order No. 14 denying Arkla's proposal to amend its rate increase Application for new depreciation rates and expense by approximately \$13 million. At the public hearing, Arkla

rate design, rate of return, various tariff issues, billing determinants, master metering/combined billing, rate case expense, and Arkla's proposed riders.

LITIGATED ISSUES

Below are the Commission's findings on issues litigated by the parties in this proceeding:

I. RATE BASE

RB-5 Working Capital Assets – MBSA/Lead Lag Study

For approximately the past twenty years, this Commission has used the Modified Balance Sheet Approach ("MBSA"), either in the absence of a lead-lag study ("LLS") or as a check on a LLS filed by a utility (Order No. 7 of Docket No. 84-199-U). This approach has been affirmed on appeal in General Telephone Co. of the Southwest v. Arkansas Public Service Commission, 23 Ark. 595, 751 S.W.2nd 1 (1988), General Waterworks of Pine Bluff v. Arkansas Public Service Commission, 25 Ark. App. 49, 752 S.W. 2nd 52 (1988), and Associated Natural Gas Company v. Arkansas Public Service Commission, 25 Ark. App. 115, 752 S.W. 2d 766 (1988). The MBSA recognizes three basic facts: (1) a utility has investments in assets other than plant which are necessary to provide utility service, and on which a return should be allowed; (2) a utility has sources of funds, other than equity and long-term debt, which should be included in the capital structure; and (3) all liabilities are fungible sources of funds that are used to fund each and every asset of the utility. A corollary of this third point is that zero-cost liabilities should be placed in the capital structure in calculating the utility's cost of capital.

A LLS attempts to measure the advances and delays involved with expenses and revenues associated with a company's operations on a day-to-day basis. The lags are generally

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stated that it was now requesting a rate increase of $14.6 million. (T. 9) associated with the delay from when customers receive service and when they pay for such service. The leads are associated with the time between when goods and services are rendered to the utility and when the utility pays for the goods and services. A LLS generally will result in a ratio of lead or lag days to the number of days in a year. If the LLS indicates a net lag (positive), such net lag indicates that on average the utility is providing net capital ahead of time to finance customers' normal lag in payment of bills, and this amount should be added to rate base. If there is a net lead, such net lead implies that the utility has a source of zero-cost capital from suppliers of goods and services, which amount should be used to reduce rate base.

A major presentation difference between the MBSA and a LLS in a rate case is that the MBSA has implications for both rate base and the capital structure, while the LLS simply increases or decreases the rate base. Of course, if both are done properly, the revenue requirement results should be approximately equivalent. The MBSA will necessarily result in a greater rate base because the expense lag is not deducted from rate base as is the case with a LLS. Further, the MBSA will necessarily result in a smaller rate of return since the expense lag is comprehended as zero-cost capital. Expenses incurred by the Company give rise to liabilities to be paid by the Company. Further, the lag associated with billing and collecting revenues derived from providing service to ratepayers causes assets, specifically accounts receivable, to be created. (T. 370) The MBSA provides a similar measurement of working capital in that it measures, through thirteen-month averages, leads and lags comparable to leads and lags stated in the Company's LLS. (T. 374 and T. 379)

The rationale for placing all liabilities in the capital structure with the MBSA is that all liabilities are sources of funds used to finance the assets of the Company. No distinction can be made as to which asset a liability is funding because the funds provided by liabilities are fungible. Therefore, to determine the total cost of funds for the Company, the MBSA posits that we cannot ignore current, accrued, and other liabilities. This Commission has consistently acknowledged the concept of fungibility going back at least thirty years. This position has also been accepted by the Arkansas Court of Appeals in Southwestern Bell Telephone Company v. Arkansas Public Service Commission, 24 Ark. App. 142, 751 S.W. 2d, 8 (1988).

Arkla implied that the MBSA method is out-of-step with the rest of the country. (T. 747-748, 769) Arkla witness Adams, using Arkla Exhibit MJA-1, testified that 41 of 51 regulatory jurisdictions allow working capital based upon a LLS and five jurisdictions rely upon a balance sheet method. The implication from that exhibit is that the LLS is preferred across the country. However, it should be noted that Exhibit MJA-1 does not show that jurisdictions that use LLS accept a flawed or incomplete LLS. This Commission is not opposed to the use of a reliable LLS, but the use of a "sampling" technique, which can produce an unreliable LLS result, is not a sufficient substitute for an MBSA.

Arkla presented an LLS prepared by Arkla witness Tucker in Direct Testimony. In that study, the revenue collection lag was developed using a sample of 4,394 transactions for residential customers and 497 transactions for commercial and industrial customers. The revenue lag was 47.721 days and 43.126 days for residential and commercial/industrial customers, respectively. (T. 1014) Similar analyses were performed for purchased gas, income taxes, payroll, short-term incentive compensation, other operation and maintenance ("O&M") expenses, taxes other than income, interest on customer advances and deposits, minimum bank balances, and working funds. (T. 1019) As a result of his LLS analysis, Mr. Tucker recommended an addition for cash working capital to Arkla's rate base of $10,159,575. (T. 1019)

Staff witness Richmond argued that Arkla's LLS did not produce comparable results to those of the MBSA. (T. 1678) According to Mr. Richmond, the MBSA is an all-inclusive method, including all accounts and liabilities, while the LLS is not necessarily all-inclusive. The MBSA should be used to assess the reasonableness of the LLS. In particular, according to Mr. Richmond, (T. 1678-1681), Arkla's LLS as submitted in this case:

(1) failed to consider accrued interest payable on debt;

(2) failed to consider time-lags associated with amounts that are capitalized;

(3) incorrectly calculated the revenue lag-residential;

(4) incorrectly calculated the purchased gas cost-lag; and

(5) potentially had sampling errors as a general problem with the LLS. (T. 1678-1681)

Further, Arkla's application of the LLS instead of an MBSA, using its own Filing Schedules (B-4, B-5, D-5, and D-6), results in an overstatement of revenue requirement of approximately $11.5 million. (T. 444 and 1085-1086) Because of this readily discernible overstatement and the readily identifiable deficiencies in Arkla's LLS, Mr. Richmond concluded that there was a problem with Arkla's LLS, and that the MBSA better reflects the cash working capital requirements of Arkla. (T. 444-445)

Another, more general, problem with Arkla's LLS identified by Mr. Richmond is that it relies upon samples, which may not encompass all of the days in the test year. In sharp contrast, the MBSA is all inclusive. (T. 451 and T. 455) It considers *all* liabilities and assets and *all* days of the test year, since each end-of-month balance includes the effects of all of the days in the month.

For Staff's MBSA, Staff witness Richmond calculated Working Capital Assets ("WCA") as an addition to rate base, and included current, accrued, and other liabilities ("CAOL") at their appropriate costs. Mr. Richmond calculated $121,536,104 for WCA based on a 13-month average of asset accounts for the 13 months ended April 30, 2004, as adjusted. (T. 1669) In calculating WCA, Mr. Richmond made adjustments to the Company's calculations in order to derive more representative balances for: (1) storage gas inventory; (2) bank account and cash amounts; (3) Accounts Receivable Contra account and Note Receivable-Associated Company account related to factoring; (4) Accumulated Provision for Uncollectible Accounts Receivable for bad debt reserve; (5) Unbilled Customer Accounts Receivable; (6) Deferred Arkansas Rate Case Expense; and (7) Miscellaneous other adjustments. (T. 1670-1673) The net effect of Mr. Richmond's adjustments is an increase in WCA of $65,786,281, resulting in a balance of $121,536,104. (T. 1673)

For the CAOL component of his MBSA, Mr. Richmond calculated the average CAOL on a total company basis for the test year, using 13 month averages ending April 30, 2004, for all liabilities. (T. 1706) In particular, Mr. Richmond included dividends payable and interest payable. (T. 1675-1677) (T. 1454) Mr. Richmond calculated CAOL of $155,923,798. (T. 1677)

AG witness Marcus agreed with the inclusion of interest payable as a zero-cost component of CAOL.

Arkla disagreed with all of Staff witness Richmond's adjustments with the exception of his adjustment for purchased gas lead (T. 1021-1031). Arkla witness Tucker disagreed with the inclusion of accrued interest and dividends payable in CAOL at zero-cost because those amounts belong entirely to the providers of capital and the rates of return that lenders and stockholders demand reflect these discrete payment conventions. (T. 757-758, 924, 1026)

In Rebuttal Testimony, Arkla witness Harder proposed adjustments to Staff's WCA in the amount of $18,764,863 for gas in storage inventory and unbilled revenues. (T. 131-133) Staff witness Richmond agreed with those adjustments to gas storage inventory and unbilled revenues which resulted in an adjustment of $84,551,144 and a revised balance of $140,300,967. (T. 1703-1706) However, Mr. Richmond did not agree with Mr. Harder's proposed increase in cash and cash equivalents in WCA by $5,427,354 and deferred rate case expense in WCA. (T. 1704-1706)

Arkla witness Adams alleged in Rebuttal Testimony that over one-half of the CAOL included by Staff in the capital structure either does not represent a source of funds or is not a zero cost source of funds: (1) $5.6 million in Accumulated Provisions for Injuries and Damages; (2) Pension Liability; (3) Other Post-Employment Benefits; and (4) Notes Payable-Associated Companies. (T. 758-762)

Staff witness Richmond disagreed with those claims, with the exception of the removal of the 13-month balance of $21,386,116 in the Post-Retirement-FAS 106 liability account from

CAOL (T. 1710-1714). AG witness Marcus also argued for inclusion of the reserve for Injuries and Damages in CAOL. (T. 135) Staff witnesses Richmond and Brown also disagreed with Arkla's claims that accrued interest payable and dividends payable should not be included in CAOL. (T. 1715-1716, 1886-1887)

Additionally Mr. Richmond made adjustments to include $12,094,413 in Accounts Payable-Gas to recognize liability for additional firm storage capacity, $921,953 for an update of gas storage inventory amounts, and increases for accrued dividends payable. (T. 1717)

As a result of these revisions, Staff's revised CAOL is $147,652,949, which is a decrease of $8,270,849 from CAOL in Staff's Prepared Testimony. (T. 1717)

Mr. Richmond also modified Accumulated Deferred Income Taxes ("ADIT") as of April 30, 2005, from the Company-proposed $33,076,031 to $37,046,891. This difference is related to the depreciation portion of ADIT, and is based on Staff's updated depreciation expense for the *pro forma* year. (T. 1717-1718) Mr. Richmond also proposed that, if Arkla's proposed new depreciation rates are accepted, any changes in timing differences between book and tax depreciation be appropriately reflected in ADIT.

The Staff has met the threshold issue of identifying a sufficient number of flaws in the Company's lead-lag study, therefore, it is appropriate to utilize Staff's MBSA in this particular case. We comment on several of the contested issues.

First, we note that the Company fails to understand the Staff's rationale for inclusion of accrued interest and dividends payable as zero-cost sources of capital. Because investors in Company debt instruments and in common stock do not immediately receive returns on their investments, but receive the required returns with a lag, those same investors require correspondingly higher returns than if cash flows were received daily or weekly. Further, those higher costs of debt and equity are reflected in market-based methods for determining those costs. This Commission properly reflects those market-based costs in rate determinations. Until dividends and interest are paid, the Company has the use of that money. Without appropriate adjustments for accrued interest and dividends payable, the Company's ratepayers would be paying twice for that lag in payments to debt-holders and stockholders. (T. 1887-1888) In particular, the Commission's preferred method for calculating the cost of equity, the Discounted Cash Flow ("DCF") Method, *explicitly* includes as a *component* of the DCF calculation the dividend yield, (Dividend/Market Price). Because of the lag in receipt of dividends, reflected in dividends payable, the market price is correspondingly smaller, and the dividend yield is greater. This makes the DCF estimated cost of equity larger. Consequently, shareholders are already allowed a higher return for the lag in dividend payments. We agree with Staff that accrued interest and dividends payable, as calculated by Staff, should be included at zero-cost in CAOL.

Although the Company purportedly attempted to include accrued interest, it did so using a lag of only 32.958 days, based on the timing of Arkla's payment of interest to the parent company. (T. 1626-1627) This is significantly shorter than Staff witness Richmond's accrued interest lag of 91.25 days, based upon the fact that interest is paid at six month intervals. (T. 1676) We agree with Staff's approach, as ratepayers should not be penalized because Arkla turns the money over to its parent more often than necessary.

With regard to Account 228.2 Injuries and Damages-General Liability, Injuries and Damages- Workers Comp, Staff has included these expenses in revenue requirements, so that ratepayers are paying those expenses on a daily basis. This is shown in the Surrebuttal Testimony of Staff witness Richmond, pp. 28-9 and the Surrebuttal Testimony of Staff witness Malone, p. 13. We agree with Staff that Account 228.2, as adjusted by Staff, should be included at zero-cost in CAOL.

With regard to Account No. 228.3 , Pension Liability, excluding Other Post-Employment Benefits ("OPEB"), Staff has already included these expenses in the revenue requirement, so that ratepayers are already paying those expenses on a daily basis. This is shown in the Surrebuttal Testimony of Staff witness Malone, pp. 8-11. We agree with Staff that Account 228.3, as adjusted by Staff, should be included at zero-cost in CAOL.

With regard to Account No. 233, ST Notes and LT Payable to Associated Companies, the Staff eliminated the interest-bearing portion of the account from Current, Accrued, and Other Liabilities. This is addressed in the Surrebuttal Testimony of Staff witness Richmond, pp. 19-20. In Sur-Surrebuttal Testimony, Arkla witness Adams agreed that Staff correctly removed the interest bearing portion of this account. We agree with Staff that Account 233, as adjusted by Staff, should be included at zero-cost in CAOL.

Arkla witness Adams argued that the low overall rate of return recommended by Staff is attributable to the application of the MBSA. (T. 773) As we discussed earlier, the application of the MBSA will necessarily result in a smaller rate of return *but a greater rate base.* Consequently, there is nothing inherently punitive about the MBSA. Further, as we discuss later, Staff witness Brown has shown that Staff's overall recommendations, including return on equity, result in Funds from Operations Interest Coverage of at least 5.0, Funds from Operations to Total Debt Coverage of at least 24%, and a total debt ratio of 54%. (T. 773, 1127-1128) Each of these financial measures meet or exceed Standard and Poor's benchmarks for an A-rated utility with a business position of 3[4].

One other issue related to cash working capital needs to be addressed. Staff witness Brown argued that the application of the MBSA in this case produces reasonable results, and, in particular that the MBSA method increases Arkla's revenue requirement by $3.5 million. (T. 1884-1885) The Company attempted to disprove that allegation on cross-examination of Mr. Brown at hearing.

As discussed in that cross-examination colloquy, the $3.5 million increase was determined by taking Staff's rate base of $469 million, found in Surrebuttal Exhibit GPF-2, page 1 of 1 (T. 1058, line 13; T. 499-500), multiplied by a pre-tax cost of capital of 7.19 percent to get a result of $33,710,198. (T. 500) Compare this to the result without the MBSA method: multiply Staff's net utility plant in service of $328 million[5], found in Surrebuttal Exhibit GPF-2, page 1 of 1 (T. 1058, T. 500) times the pretax cost of capital of 9.2 %, without CAOL and zero cost in that calculation, to obtain $30,226,361. The difference between these two calculations is $33,710,198 - $30,226,361, or approximately $3.5 million.

[4] Standard and Poor's rates companies on a Business Position Scale of 1 to 10 with 1 being the most safe and 10 being the least safe. A Business Position of 3 is above average. All of the sample utility companies used by Staff are rated as a 3 on the Business Position scale.

[5] The primary difference between Staff's rate base of $469 million and Staff's net utility plant in service of $328 million is $140 million in working capital assets.

On cross-examination, Arkla's counsel attempted to disprove this result. Counsel posited that in his MBSA revenue requirement calculation, Staff witness Brown should have included $67 million for gas in storage, $2.7 million for materials and supplies, and prepayments of $435,000 to obtain a rate base figure without MBSA of approximately $399 million. (T. 505-506) Accordingly, if we multiply .092 times $399 million, we obtain $36,713,000. Arkla's counsel then asked Mr. Brown if, in fact, the MBSA revenue requirement is less than the lead lag revenue requirement (T.507). Mr. Brown did not agree with those calculations. (T. 507) He did not agree that the $36.7 million figure was calculated correctly. Mr. Brown noted that the latter calculation posited by Arkla's counsel is making an apples-to-oranges comparison. (T.516)

While there was much wrangling back and forth between Mr. Brown and Arkla's counsel (T, 507-519), the ultimate source of the disagreement is the determination of the proper "starting point" in the calculation. Mr. Brown claims that the proper starting point is a net utility plant rate base of $328 million, while the Company believes that the proper starting point should include, in addition to net utility plant, gas in storage, materials and supplies, and prepayments, for a total amount of $399 million. We agree with Staff on this point. Staff's MBSA is all-inclusive; it is improper to use as a starting point only a portion of the working capital assets, gas in storage, materials and supplies, and prepayments, which are part and parcel of the overall MBSA approach. For example, if we are to include these additional assets as a staring point, then perhaps additional zero-cost liabilities, such as Accounts Payable-Gas (T. 1717 and T. 510), should be included at the starting point, as well. The correct starting point is the one used by Mr.

Brown. Consequently, Mr. Brown is correct that the MBSA increases revenue requirement by approximately $3.5 million relative to the MBSA not being used.

The Commission agrees with Staff witness Richmond's calculations of the MBSA for purposes of calculating cash working capital in this case. In the future, however, should Arkla or any other utility prepare and present a reliable LLS, thereby producing a more comparable and accurate result for cash working capital as does the MBSA, the Commission will consider utilizing that approach.

RB-5A Gas in Storage Inventory

The Company claims that the appropriate gas in storage ("GIS") inventory balance to be included in rate base is $67,286,309. (T. 173) This figure reflects actual month end balances for the period May 31, 2004 through April 30, 2005, plus an adjustment to reflect the annualized effect of the additional firm storage capacity which the Company acquired from CenterPoint Energy Gas Transmission ("CEGT") on April 1, 2005. The Commission approved the Company's purchase of this additional firm storage capacity in Commission Docket No. 04-029-U, Order No. 8. (T. 129-130)

Staff initially contested Arkla's claim. However, in his Surrebuttal testimony, Staff witness Richmond accepted the Company's GIS inventory balance but noted that the Company had failed to appropriately recognize the payable associated with this balance.

AG witness Marcus proposed to reduce Arkla's GIS inventory by $1,146,597 to reflect the elimination of an excess average balance caused by purchasing more gas early in the injection cycle. (T. 1476-1478) He also reduced the GIS balance by $12,095,413 to eliminate the additional costs associated with new capacity because the gas will not be purchased and stored until after the end of the *pro forma* year. (T. 1478-1479)

Arkla disputed both of Mr. Marcus' proposed adjustments. Arkla witness TheBerge argued that Mr. Marcus had not shown that his "theoretical" storage cycle was more realistic than the actual storage cycle or that injections in excess of equal daily injections were excess. While the goal may be to inject on an equal daily basis, that goal is rarely, if ever, achieved for a variety of reasons. (T. 722) As acknowledged by Mr. Marcus on cross-examination, actual injections should take into consideration projections of price and must also recognize the physical constraints on injections that exist in the later months of the injection period. (T. 332-333)

With regard to the additional storage contract with CEGT, Arkla witness Harder noted that Arkla had a firm entitlement to the additional storage which has now been approved by FERC and will be available this winter. Because Arkla contracted for this capacity during the *pro forma* period, the additional allowance qualifies for recognition. (T. 216-218)

We will accept the GIS balance agreed to by Staff and Arkla. We agree that the additional inventory associated with the additional firm storage capacity is properly recognized in this proceeding. We also accept the GIS balance for existing storage based on the actual balances during the period May 31, 2004 through April 30, 2005.

RB-3 Accumulated Depreciation - Retirement Work In Progress ("RWIP")

Staff witness Williams testified that any RWIP balances related to projects not completed by the end of the *pro forma* year should be eliminated. Staff Adjustment RB-3 eliminated the

RWIP balance at test year end amounting to $5,712,053. (T. 1935) Arkla witness Harder testified that the pending decrease in the reserve for accumulated depreciation for RWIP at the end of the *pro forma* period should be accounted for as a reduction to accumulated depreciation, otherwise plant-in-service will be understated. Mr. Harder argued that RWIP represents gas plant that has been physically removed from service and Gross Plant In Service ("GPIS"). He further contended that, under the FERC Uniform System of Accounts ("USOA"), Arkla is allowed to include RWIP in a separate subaccount. According to Mr. Harder, this treatment of RWIP, as a reduction to the accumulated reserve for depreciation is both appropriate and necessary. (T. 118-119)

In surrebuttal testimony, Staff witness Williams disagreed with Arkla witness Harder that RWIP should be included in accumulated depreciation. Ms. Williams stated that, contrary to Mr. Harder's rebuttal testimony, the Company stated in response to Staff Interrogatory No. AUD-401 that, although assets have been physically removed from service, they have not been removed from GPIS. Ms. Williams asserts that these amounts are not reflective of the final accounting of costs and benefits related to retirements that are in progress, are still currently included in GPIS, and therefore should not be included in Plant In Service (PIS). (T. 1952) In sur-surrebuttal testimony, Mr. Harder continued to argue that RWIP should be included in rate base. He contended that RWIP represents additional investment by the Company that should be included in plant. Mr. Harder further asserted that if the asset is not removed from service, then RWIP represents additional costs associated with the asset. If the asset has been removed, then RWIP should be netted against accumulated depreciation. (T. 214-215)

The Commission finds that the Staff's treatment of this issue represents a more reasonable resolution than the Company's proposal. Arkla is essentially requesting that it should be allowed to include in rate base and earn a return on $5,084,504 of RWIP. The Staff recommends that Arkla's proposal be denied. Arkla states that under the FERC USOA, Arkla is allowed to include RWIP in a separate subaccount under accumulated depreciation. This would suggest to the Commission that the RWIP subaccount is an account where, as Staff witness Williams testified, costs are being accumulated on retirement work orders that have not been completed. As Ms. Williams further testified, the "amounts are not reflective of the final accounting of costs related to the retirements that are in progress... ." (T. 1952) In other words, it is only after the final costs of the amounts contained in the subaccount are known and finalized that the accumulated reserve for depreciation is charged or reduced. Arkla has simply not sustained its burden of proof with regard to the proper accounting treatment of RWIP nor has it adequately shown why RWIP should be included in rate base. Therefore, the Commission finds that the Company's proposed treatment of RWIP is not acceptable, and its request to include RWIP in rate base is denied.

II. OPERATING EXPENSES

IS-20 Payroll

The Company's initial filing included a *pro forma* adjustment to annualize payroll expense. This adjustment was based upon the annualization of payroll based on the level of employees at September 2004, which resulted in an annualized payroll of $33,611,947. In its rebuttal filing, the Company updated its payroll adjustment to reflect the actual payroll for the twelve months ending April 30, 2005, adjusted to reflect the competitive pay adjustment ("CPA") of 3 percent that was granted on April 1, 2005. According to Arkla witness Harder, the revised payroll adjustment would recognize a number of factors that affect the payroll, such as employee turnover, promotions, etc. (T. 141) Mr. Harder also explained that this method of annualizing payroll expense avoids any distortion of the annual payroll expense that may result from the April 1, 2004, corporate reorganization, since employee levels remained relatively stable during the 12 months ending April 30, 2005. The updated payroll adjustment resulted in an annualized payroll of $33,764,815 or $152,868 higher than the Company's initial payroll claim.

In Staff witness Malone's direct testimony, he recommended an adjustment to payroll to reflect two changes. The first change was to reflect the most recent number of employees available at the time it filed testimony, which was the number of employees at February 28, 2005. Mr. Malone explained that the Company had used a "per person" basis to calculate payroll, and by using the most recent known level of employees, its adjustment resulted in the exclusion of 44 positions that were vacant on that date. In Mr. Malone's surrebuttal testimony, he pointed out that the Company's rebuttal payroll calculation moves away from the "per person" calculation. According to Mr. Malone, the Company's rebuttal payroll calculation is affected by the corporate reorganization since the workforce continued to decline through December 2004. (T. 1980) Mr. Malone also updated his adjustment by annualizing payroll based upon the number of employees at the end of the *pro forma* year. Mr. Malone calculated his revised payroll based on the number of employees on March 31, 2005, adjusted to reflect vacancies and the CPA as of April 2005. The payroll was also adjusted for normal overtime and Short-Term Incentive Pay.

The second change reflected by Mr. Malone related to the Short-Term Incentive Plan ("STIP") and the Long-Term Incentive Plan ("LTIP"). Essentially, Mr. Malone proposed a 50/50 sharing of the incentive pay that was related to achieving financial goals. However, Mr. Malone revised his STIP adjustment in his surrebuttal. Mr. Malone indicated that, based upon his review of those costs for the *pro forma* year and the preceding three years, a three-year average of the STIP should be used to determine the STIP amount included in rates. (T. 1983)

In his surrebuttal testimony, Mr. Malone also modified his calculation of the level of overtime to be included in the cost of service in this proceeding. Similar to its surrebuttal recommendation for the STIP, Mr. Malone recommended that the overtime level be based on the average amount for the three preceding years.

The AG limited its payroll adjustments to the incentive pay components of payroll. With respect to the STIP, AG witness Marcus proposes an adjustment that is similar to Staff's in that the AG proposes a 50/50 sharing of the incentive pay related to financial goals, and that the amount be based on the three-year average. With respect to the LTIP, Mr. Marcus proposed to remove 50 percent of the Company's CEO bonus and 100 percent of the restricted stock compensation to the top four corporate officers.

In his Sur-Surrebuttal testimony, Arkla witness Harder addressed several of the payroll issues raised by Staff and the AG. He criticized the revised payroll adjustment recommended by Staff witness Malone in his Surrebuttal filing as being based upon a "snap shot" or only one point in time. However, with regard to salary and wages, Mr. Harder indicated that of the $734,704 difference between the Staff and the Company, $536,255 is the result of differences between the two parties in the capitalization rate. According to Mr. Harder, Mr. Malone used the budgeted capitalization rate from the original filing, while he used the actual capitalization rate for the *pro forma* period. (T. 223) Mr. Harder identified the remaining difference of $198,449 as related to the difference in the level of employees due to turnover. (T. 224) With respect to Staff witness Malone's use of the three-year average overtime pay, Mr. Harder suggested that the increased overtime is a direct result of the corporate reorganization and argued that Mr. Malone failed to take that into consideration. Finally, in his Sur-Surrebuttal testimony, Mr. Harder accepted Staff's and the AG's recommendation to use a three-year average for the STIP, but rejected the 50/50 sharing of those costs.

The Company's payroll claim can be broken down into three components – regular salaries and wages, overtime payroll, and incentive compensation. The parties disagree on how these three components should be determined. With regard to regular salaries and wages, the Company's rebuttal approach considers the CPA-adjusted actual payroll (and the actual *pro forma* year number of employees) to be representative of the ongoing level of payroll. Arkla witness Harder indicated that the restructuring in April 2004 resulted in a reduction of the workforce that is properly reflected in the *pro forma* year employee and wage levels that reflect employee levels after the corporate reorganization. In his rebuttal testimony, Mr. Harder stated that he revised his payroll adjustment to the *pro forma* period because the workforce was relatively stable and was not tainted by workforce reductions.

Staff witness Malone proposed to determine annualized regular salaries and wages by first calculating the most recent level of salaries and wages per employee, including the April 1, 2005, CPA adjustment. This cost per employee was then multiplied by the end of *pro forma* year employee level to derive the Staff's recommended allowance for salaries and wages.

Based on our review, we are satisfied that Arkla's *pro forma* year wages, adjusted for the April 1, 2005, CPA increase, reflect the impacts of the restructuring which occurred prior to the *pro forma* year. Based on the information before us in this proceeding, we are not convinced that the Staff's proposal to use employee levels as of a single point in time is representative of Arkla's normal ongoing employee levels upon which forward-looking rates are to be based. Accordingly, we reject Staff's adjustment to regular salaries and wages.

With regard to overtime, Arkla witness Harder again proposed to utilize the actual level of overtime during the *pro forma* period. Staff witness Malone proposed to base overtime on the average level during the three preceding years. Mr. Harder argued that Mr. Malone's use of a three year average fails to recognize that the employee reductions resulting from the April 2004 restructuring will affect the level of overtime required prospectively. In his Sur-Surrebutta testimonyl, Mr. Harder noted that Arkla's use of the *pro forma* period level of overtime reflects the impact of the reorganization.

We agree that reductions in the number of employees may increase the need for overtime for remaining employees. Accordingly, we conclude that use of a multi-year average for overtime is not appropriate in this case because it includes periods prior to the recent restructuring. Therefore, we reject Staff's adjustment to overtime.

Regarding the incentive compensation portion of the payroll, it should be recognized that incentive pay can be considered "at risk". As such, there is no guarantee that incentive payments will be made in any given year. As pointed out by Staff witness Malone and AG witness Marcus, financial and customer service goals are established and have to be achieved in order for payments to be made under the plan. (T. 1963, 1372) In fact, Mr. Marcus points out that in 2001, one of the corporate affiliates from whom the Company receives charges did not make incentive payments to its employees. (T. 1374) The other aspect of incentive payments is that the amount paid can be affected based upon whether the goals were simply achieved or were exceeded. In other words, if the results of operations exceed the goals by certain benchmarks, the incentive payments are higher than they would have been if the goals were achieved at the minimum level. This means that even if incentives were paid every year, the level of incentives paid may fluctuate from year to year. Therefore, the incentive payments made in any single year cannot be considered the normal level. Accordingly, the Staff and AG's recommendation that the average incentive pay be used in determining the allowable incentive pay is adopted.

Both Staff witness Malone and AG witness Marcus recommend that the Company be allowed to recover only 50 percent of the incentive pay related to financial goals. This sharing of the financial goals has merit because both shareholders and ratepayers stand to benefit from the Company's achieving these goals. Shareholders benefit because, when the goals are achieved or exceeded, additional income is earned which translates into increased shareholder value. Ratepayers benefit because, when the Company is able to achieve additional income, it is able to pass the additional income on to its customers by keeping rates down or filing less frequent rate cases. Although the Company rejects the 50/50 sharing by stating that the STIP is performance-related, it has not denied nor presented any contrary evidence that financial goals govern the payment of the STIP.

With regard to the LTIP, AG witness Marcus recommends that 50 percent of Arkla's share of the incentive bonuses paid to CenterPoint's CEO be disallowed to reflect benefits to both ratepayers and shareholders. (T. 1374) In support of the position, Mr. Marcus noted, in his Surrebuttal Testimony at page 18, that the compensation of CenterPoint's CEO has increased by 93 percent from 2001-2004. In his Sur-Surrebuttal testimony, Arkla witness Harder argued that incentive bonuses are based on individual performance and are an appropriate part of overall compensation. AG witness Marcus also recommended that all of the Restricted Stock bonuses paid to certain corporate executives be removed from the cost of service. (T. 1375-1376) He argued that costs should be borne by shareholders since they are given to only a few highly paid individuals.

In his Sur-Surrebuttal testimony at pages 24-25, Arkla witness Harder rejected the 50/50 sharing of the STIP, but accepted the 50/50 sharing of the LTIP costs. Hence, only the STIP sharing is currently being contested by the Company. As we explained above, there are benefits to both ratepayers and shareholders when the Company achieves the financial goals that trigger the payment of incentive compensation. Therefore, we accept the recommendation that there be a 50/50 sharing of the STIP. With regard to AG witness Marcus' recommendation to disallow 100 percent of the restricted stock payment to certain corporate officers, we find that Mr. Marcus has not provided sufficient reasons to treat these employees differently. As a result, we decline to accept his recommendation. We also note that by the parties' agreement on the 50/50 sharing of the LTIP and our acceptance of the 50/50 sharing of the STIP, the CEO bonus is effectively being shared on a 50/50 basis between ratepayers and shareholders. (TR 89-90.) As a result, AG witness Marcus' recommendation regarding the CEO bonus is resolved, and a separate adjustment is not needed. In summary, an adjustment to payroll expense of $530,874 is found appropriate in this proceeding. This reflects Staff's adjustment to disallow 50 percent of STIP expense.

Depreciation – Rates (IS-48 Depreciation Expense)

In its Application, Arkla proposed to continue to utilize the depreciation rates approved in Arkla's prior rate case and elected not to present a new depreciation study in this proceeding. (T. 85) Because of concerns which were raised in that rate case (Docket No. 01-243-U) with regard to net negative salvage, Staff witness Freier prepared a depreciation study and has proposed new depreciation rates. Based on the findings of her study, Ms. Freier recommended that the Company's proposal to adopt the currently authorized depreciation rates be rejected. Adoption of Staff witness Freier's recommended depreciation rates will result in a composite depreciation rate of approximately 3.80 percent compared to the current composite rate of approximately 5.42 percent. (T. 2007-2009)

According to Ms. Freier, the primary factor causing the difference between her proposed depreciation rates and the current rates relates to net negative salvage for the mains and services accounts. The current depreciation rates for mains and services are based on negative net salvage factors of -115 percent and -275 percent, respectively. (T. 2012-2013) Based on her analysis, Ms. Freier proposed negative net salvage allowances of -70 percent for Mains and -115 percent for services. (T. 2032)

The salvage ratios underlying Arkla's current depreciation rate are based on the ratio of the cost of removal net of any gross salvage realized compared to the original cost of the assets retired and removed from service. Staff witness Freier notes that this has the effect of not stating retirement amounts and the negative net salvage amounts in comparable dollars because of the historical inflation which has taken place from installation to removal. According to Ms. Freier, the failure to restate historical original costs on the same basis as retirements "interjects considerable historical inflation differences into the calculation and significantly overstates the appropriate net salvage [and] the depreciation rates ...." (T. 2013) Accordingly, Ms. Freier developed her negative net salvage ratios and, in turn, her depreciation rates by restating retirements, gross salvage and cost of removal on a constant price level. (Id., p. 10.)

In addition to developing revised depreciation rates, Staff witness Freier also made several other recommendations with regard to depreciation expense. These recommendations deal with various data retention and recordkeeping issues as set forth on pages 16-18 of her Prepared Testimony. Ms. Freier also identified six accounts that are fully recovered or overrecovered including: Other Structures-Distribution; Cast Iron Mains; Other Structures-Levy PH (call center); Structures & Improvements-Services; Data Processing Equipment-Misc.; and Other Equipment-Communications Equipment-Mtr. She recommended that depreciation accruals cease on these and any other accounts where the reserve ratio equals 100 percent plus or minus any applicable net salvage. (T. 2032)

In his rebuttal testimony, Arkla witness Harder argued that Ms. Freier's proposed depreciation rates significantly understate the appropriate allowance for depreciation expense. Mr. Harder indicated that Arkla did not propose to adjust its current depreciation rates in order to narrow the issues in the instant proceeding. However, in response to Ms. Freier's proposals, Arkla submitted its own new depreciation study, sponsored by Mr. John Spanos.[6] (T. 170)

In his study, Mr. Spanos took exception to Ms. Freier's net salvage calculations. He argued that the Commission should follow the traditional method of calculating net salvage, as it has in the past. He noted that the traditional approach (comparing net salvage to original cost of the retired plant) collects net salvage ratably over the life of the plant, from the customers served by that plant. Mr. Spanos claimed this approach is both equitable and consistent with sound ratemaking principles. In contrast, he contended Staff witness Freier's approach fails to recover the total loss in-service value (depreciation plus net salvage) over the life of the asset. Mr. Spanos testified that by excluding inflation, Ms. Freier's proposal will delay recovery of full service value and create intergenerational inequities. (T. 370-371, 383-384)

In addition to responding to Staff witness Freier with regard to net salvage, Arkla witness Spanos also presented a new depreciation study to demonstrate that Ms. Freier's proposed depreciation rates were too low. As part of this study, Mr. Spanos developed new estimates of service lives and salvage percentages. In addition, the depreciation rates which he developed were based on converting from average life group ("ALG") to equal life group ("ELG") procedure.

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[6] In our Order No. 14 in this docket dated August 4, 2005, we ruled that this study was proper rebuttal, but could not be used to amend the Company's application to seek a higher depreciation allowance.

In her *Surrebuttal* Testimony, Ms. Freier argued that Mr. Spanos' proposal should be rejected. She noted that the composite depreciation rate proposal by Mr. Spanos would be 7.42 percent compared to the composite of 5.42 percent based on Arkla's current depreciation rates and her proposed composite of 3.80 percent. She compared this composite with the composite rates for other LDCs regulated by this Commission and concluded that the new depreciation rates proposed by Arkla are excessive. (T. 2045-2047)

In response to Mr. Spanos' criticisms of her proposal to restate the salvage allowance on a constant dollar basis, Ms. Freier noted that her treatment is fundamentally consistent with the treatment of negative salvage used in Entergy Arkansas, Inc.'s[7] nuclear decommissioning calculations. Those calculations provide for the recovery of decommissioning costs over the life of the plant in levelized, not constant, dollars. (T. 2057)

Ms. Freier also responded to Mr. Spanos' proposal to utilize the ELG procedure for calculating depreciation rates by noting that this procedure was inconsistent with Commission practice. Ms. Freier explained that both ALG and ELG are systematic and rational frameworks for calculating depreciation accruals over the life of the asset. However, ELG would cause depreciation rates to be higher in the early years of an asset's life. Moreover, because of the increasing cost of plant over time, she argued that depreciation expense will always be higher under ELG than under ALG. (T. 2047- 2050) This is particularly important for a utility such as Arkla that is adding new plant as a result of its main replacement program (TR 273.)

In his Sur-Surrebuttal testimony, Mr. Spanos argued that comparisons of composite depreciation rates are not meaningful without more specific information. (T. 394) He also claimed that the higher depreciation accruals under ELG compared to ALG are offset by future return on rate base savings. (T. 395-397) In addition, Mr. Spanos noted that Staff witness Freier's adjustment to levelize salvage cost recovery will result in the underrecovery of future net salvage costs. He further argued that, because the accruals for the recovery of original cost are not stated in levelized dollars, Ms. Freier's procedure to restate salvage costs creates an inconsistency between the recovery of the original cost of the plant and salvage costs. Finally, Mr. Spanos noted that ratepayers receive a rate base deduction for the amounts they provide for the recovery of future net salvage because those amounts are included in the balance of accumulated depreciation until the net negative salvage costs are incurred. (T. 397-399)

With regard to the proposal to adopt ELG depreciation, we agree with the criticisms raised by Ms. Freier. As we have noted in the past, ELG will continue to result in higher depreciation rates and expense as long as a utility's plant continues to grow. The higher accruals in the early years of an asset's life exacerbate the problem that capital costs are already front end loaded because of the higher return on investment in the early years of that asset's life. Both ALG and ELG provide for full recovery of the investment in an asset over its life when coupled with remaining life depreciation. We conclude that ALG better balances the interests of shareholders and ratepayers and reject Arkla's argument that the ELG procedure is appropriate to establish depreciation rates.

We are also very concerned about the high level of negative net salvage associated with Arkla's mains and services. This issue arose previously in Arkla Docket No. 01-243-U in which Arkla was directed to perform a removal cost study. However, according to Staff witness Freier,

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[7] Entergy Arkansas, Inc. is a retail public electric distribution utility regulated by this Commission.

that study did not explain why Arkla's net salvage values are so far out of the norm. As a result, Ms. Freier proposed an inflation adjustment as a means of addressing this issue. (T. 271) Ms. Freier's methodology for calculating net salvage on a constant dollar basis represents a departure from the historical procedure we have followed to set Arkla's depreciation rates. However, we note that the net salvage allowances recommended by Ms. Freier of -70 percent for Mains and -115 percent for Services are still significant and are in line with experience elsewhere as cited by Mr. Spanos. (T. 218-220) Moreover, the use of remaining life depreciation will ensure that Arkla will fully recover its original investment and the actual amount it incurs for negative net salvage. Accordingly, we adopt Staff's proposed net salvage values and, in turn, Staff's depreciation rates as a means of capping net salvage cost.

We agree with Ms. Freier's recommendation that depreciation should cease on all plant accounts where depreciation accruals are at or above 100 percent adjusted for net salvage. Arkla has accepted the Ms. Freier's recommendation that Arkla be required to apply the depreciation rates approved by this Commission to each of its accounts whether is direct-assigned allocated, general or shared, with the condition that it be allowed to use fixed life depreciation for certain general plant assets. (T. 978-979) Given the low dollar value of these assets, this is reasonable and is accepted. Finally, we hereby require Arkla to implement the new reporting requirements proposed by Ms. Freier. We are concerned about the issues that have arisen with regard to plant accounting under Arkla's new SAP accounting system ("SAP") and will take this opportunity to ensure that they are corrected. Accordingly, Arkla is directed to:

- Retain both electronically and in hard-copy format, the data that was ultimately provided in the responses to Staff data requests AUD-057 and AUD-058, to be used in future depreciation studies, as well as to keep the same level of data going forward.
- Perform an analysis and produce a report that 1) identifies each and every missing retirement for all accounts other than mains and services since SAP was implemented; 2) describes the processes followed in identifying and reporting the missing data; and 3) provides any source documents that were relied upon. This report should be filed with the Commission by March 31, 2006.
- File data annually that would support a depreciation study, including by activity year, plant additions by vintage, retirements by vintage, salvage and cost of removal by individual plant account, for the preceding calendar year. The first submission should be filed by March 31, 2006, and include the two years of data for 2004 and 2005, and thereafter include one year of data.

IS-65 Test Year Audit Sampling

For purposes of this proceeding, Staff and Arkla agreed to utilize sampling to evaluate the amount of costs included in Arkla's test year that are not properly recovered from ratepayers. At pages 22 through 25 of her Prepared Testimony, Staff witness Fritchman described the problems that Staff encountered in obtaining the necessary sampling and conducting its audit in a timely manner. Because of these difficulties, Staff was unable to complete its review prior to its direct testimony. Accordingly, Ms. Fritchman proposed to eliminate $1,580,576 from test year expenses for amounts not necessary to provide utility service (Adjustment IS-65). This adjustment was based on the percent of disallowed operating expenses in Docket No. 01-243-U applied to the sample populations in this docket.

In response, Arkla presented the Rebuttal Testimony of Mr. Michael Hamilton and Mr. Walter Fitzgerald to explain why it believed Staff encountered problems and to explain the efforts Arkla had undertaken to satisfy the Staff's requirements. It was the Company's position that it had at that time provided Staff with the requested information necessary to complete its analysis and to substantiate its operating expenses. (T. 965-968)

In surrebuttal, Ms. Fritchman provided updated recommendations based on the Staff's completed test year audit. Ms. Fritchman testified that, while Staff was unable to conduct the sampling effort to the extent it desired, it was able to develop a recommendation based on limited review of source documentation. Ms. Fritchman's revised recommendation was to reduce test year costs by $682,767 to exclude amounts not properly recovered from ratepayers. This amount included: $599,101 based on sampling results; $80,889 based on the description of natural accounts allocated to Arkla by CenterPoint Energy Service Company, Entex and Arkla Corporate; and $2,778 of purchases on a company provided credit card (P-card) at CenterPoint Energy Service Company. (T. 1584-1590)

In Sur-Surrebuttal, Mr. Fitzgerald argued that the portion of Ms. Fritchman's adjustment related to out of period items is improper because there are expenses in any 12-month period that lag into the next 12 months. (T. 1580) However, as noted during Ms. Fritchman's cross-examination , the Company selected the test year and then had the opportunity to make any necessary adjustments for such costs and did not do so. (T. 174) It also had the opportunity to provide information regarding such costs to the Staff but did not do so. (TR 183)

Accordingly, we adopt the Staff's audit adjustment to exclude $682,767 from test year costs. These costs include out-of-period expenses, contributions, entertainment and other expenses routinely disallowed by this Commission as not properly recovered from ratepayers.

IS- 22 Retirement Plan and Benefit (Pension Expense)

Staff witness Malone testified that pension expense was adjusted based on the most recent actuarial report rather than the 2005 budgeted amount proposed by Arkla. Mr. Malone stated that the difference between the Arkla and the Staff pension expense adjustment is a large December 2004 contribution by CenterPoint Energy to its pension plan which greatly reduced *pro forma* year pension expense. (T. 1965-1966) Arkla witness Harder testified that Arkla's pension expense is susceptible to annual fluctuations caused by the actuary's estimate of Arkla's pension contribution, sudden changes in the market value of plan assets, and the amount contributed by the Company to the plan. Arkla contends that the large December 2004 contribution to the plan will have a short-term impact on Arkla's pension expense and the actuary's estimate does not fairly represent an on-going level of pension expense for ratemaking purposes. Mr. Harder used a three-year average of pension expense for calendar years 2002-2004. Mr. Harder argued that a three-year average to normalize pension expenses mitigates the short-term impact of recent events. (T. 146-147)

The Staff testified that Arkla has not provided any evidence to show that the pension expense determined from the 2005 actuary report does not represent an ongoing level of pension expense. Mr. Malone argued that Arkla's pension expense is declining and a three-year average based on 2002-2004 pension expenses is not appropriate or representative of the ongoing pension expense level. (T. 1985-1986) In sur-surrebuttal testimony, Mr. Harder argued that Staff's approach should be rejected because (1) actuarial reports are less reliable than actual expenses, (2) the 2005 Actuarial Report forecasts includes 8 months of data that is beyond the end of the *pro forma* period, and (3) as of June 30, 2005, the pension plan assets have underperformed the return expected in the 2005 Actuarial Report. (T. 229-230)

The Commission adopts Staff's method for determining Arkla's pension expense adjustment. The Company's most recent actuarial report represents independent and reliable evidence for Arkla's *pro forma* level pension expense. The Commission also concurs with Staff's reduction of the Company's pension expense resulting from the large December 2004 contribution by CenterPoint Energy. The contribution represents a known and measurable change which should be considered in determining Arkla's *pro forma* level pension expense. The Commission agrees with the Staff's contention that the 2005 actuary report provides a better representation of ongoing pension expense than Arkla's method, which is based on an average pension expense for calendar years 2002 through 2004. Arkla's average pension expense for 2002-2004 shows that Arkla's pension expense is declining, and therefore a three-year average is not appropriate or representative of the Company's ongoing level of expense. Mr. Malone testified at the hearing that his pension expense adjustment included all known and measurable changes occurring through the end of the *pro forma* year. He further testified that Arkla's adjustment, which used the three previous years' average, would not have taken into account several changes including a half-billion dollar contribution to plant assets, the change in the work force level, the number of participants in the plan due to the sale of Texas GENCO, and the reorganization which reduced the work force levels. (T. 147)

IS-34 Corporate, Shared Services, and IT Expense

Staff Witness Fritchman testified that Arkla's test year expenses were increased to recognize the increase in costs from CenterPoint Energy Service Company ("CNP Service Co.") for corporate, shared services, and IT services performed on behalf of Arkla. These services include corporate planning, legal, human resources, security, maintenance, payroll, and computer support. (T. 1532-1533) Arkla Witness Harder argued that Staff's *pro forma* expense should be adjusted to reflect (1) the annualization of corporate allocation factors that became effective in 2005, (2) CenterPoint Energy's sale on April 13, 2005, of its interests in Texas Genco Holdings, Inc, and (3) the fact that Staff already included, in another Staff adjustment, Staff's removal of certain corporate allocated legal expenses and payroll costs. (T. 155-157) Staff testified that Arkla's projected allocation factors for April 2005 through December 2005, revised to reflect the Texas Genco sale, failed to recognize the projected savings that the Company anticipates. Regarding Arkla's contention that Staff's adjustment has already been reduced for corporate legal costs, Ms. Fritchman stated that: (1) it is inappropriate for Arkla to reduce this adjustment for the corporate legal costs disallowed in another adjustment; and (2) Arkla is attempting to recover the corporate legal cost disallowance which Arkla agreed was appropriate. (T. 1590-1592) In sur-surrebuttal testimony, Mr. Harder stated that the remaining issue between Arkla and Staff relates to the annualization of corporate allocation factors that became effective in

2005. Mr. Harder asserted that the change in allocation factors represents a reasonably known and measurable change which occurred in the *pro forma* period. He contended that Staff's reliance on cost savings expected to occur in the future does not meet this standard. Mr. Harder asserted that Staff has not: (1) attempted to reasonably measure the expected savings; (2) produced any evidence to support its inference that savings will offset the impact of the change in allocation factors; or (3) reconciled its position on this adjustment with its position on the cathodic protection expense adjustment, in which Staff indicated that costs outside the *pro forma* year should not be accepted. (T. 230-232)

The Commission finds that the Staff's calculation of this adjustment is appropriate. Any utility management decision to centralize its utility service obligations into a "shared services" contract should inherently be designed to improve service delivery and save ratepayers money, and not the reverse. Regarding the issue of Arkla's revised allocation factors from the sale of Texas Genco, Arkla in its response to Staff Interrogatory No. AUD-309 affirms that cost savings from the sale are expected to offset the change in the allocation factors. Arkla's response to Staffs Interrogatory No. AUD-309 provides concrete evidence that refutes the testimony presented by the Company. According to Ms. Fritchman's testimony (T. 1591), the Company's response to Staff Interrogatory AUD-309 states that:

> "...there are programs in place to improve the controllable expenditures in the Corporate Areas by $30M over a 3-year period (2004-2006) which will offset any impact the sale of Texas Genco might have on CNP (CenterPoint Energy) affiliates due to the change of allocation factors..."

Arkla's response to the interrogatory establishes that: (1) there are measurable expected savings to offset the impact of the change in allocation factors; and (2) a portion of the cost savings will be realized within a period which encompasses the test year and *pro forma* year. The Commission finds that the change in allocation factors and the cost savings are reasonably known and measurable changes which should both be recognized in order to produce a symmetrical result. The Company would have the Commission recognize the additional expense caused by the change in allocation factors but ignore the Company's own statement that cost savings are expected to offset the change in the allocation factors. Furthermore, the Company should take note that any decisions it makes in another jurisdiction, whether for political, legislative or economic reasons, such as its sale of Texas Genco (T. 69, 86, 157, 1591) as a quid pro quo for other concessions it received in the Texas legislative process to implement "electric retail choice," will not be allowed to have adverse cost implications on this jurisdiction's retail ratepayers. Arkansas ratepayers should be, and shall be, held harmless from decisions made by a utility in another jurisdiction that are adverse to the interests of Arkansas ratepayers.

IS -38 Interest on Customer Deposits

Because Arkla did not include customer deposits in its capital structure, the Company requests that the interest on customer deposits treated as an operating expense. The amount of operating expense that the Company recommends reflects the amount of interest payable on a 13-month average of customer deposits at the 1.8% interest rate set by Order No. 3 in APSC Docket No. 04-135-U. (T. 160-161) The Staff and the AG included customer deposits in their capital structures, using the MBSA Approach. (T. 1687, 1362)

The Commission adopts the position of the Staff and AG on this issue consistent with the Commission's decision adopting the MBSA.

IS-37 Contract Meter Reading Expense

Arkla and the Staff are in agreement on the adjustment of this expense. (T. 1724) Arkla witness Harder stated that, as the Company loses meter readers, it evaluates the feasibility of replacing those positions with contract meter readers. (T. 84) Mr. Harder further stated that the number of Company meter readers has been reduced in the *pro forma* period and replaced with contract meter readers. As a result, Arkla contends that its contract metering expense should be increased. (T. 158) The AG believes that recorded costs in this Account 902 for the *pro forma* year should be used in its entirety. The AG recommends that actual *pro forma* year spending be used for this account in order to capture everything that is occurring, rather than selectively updating pieces of it. (T. 1468-1469)

The Commission accepts Arkla's and Staff's position on this adjustment. Staff indicates that Arkla has now provided: (1) the actual amounts of contract meter reading expense for the months of March and April 2005; and (2) the corrected amounts for July through December 2004. (T. 1724) The Commission finds that this updated information provides sufficient evidence to satisfy the AG's concern that actual *pro forma* year spending be used for this adjustment.

IS -25 Employee Saving Plan Expense

Arkla and the Staff agree on the employee savings plan contribution rate. However, Arkla and Staff disagree on the proper level of *pro forma* payroll expense to which the contribution rate would be applied. (T. 1988) Arkla's and the Staff's saving plan expense 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.

III. REVENUE CONVERSION FACTOR

Traditionally, the revenue conversion factor is used to determine the revenues a utility needs to collect to allow for state and federal taxes and uncollectibles. The parties, including the AG, do not dispute the level or amounts of Arkla's revenues (IS-17) or the uncollectible accounts experience ratio determined in conjunction with Arkla's Bad Debt Expense (IS-41). The only remaining issue is whether or not late payment revenues should be included as part of the revenue conversion factor.

AG witness Marcus argued that lower uncollectible accounts expenses and the inclusion of late payment revenues reduces the level of the revenue conversion factor. Mr. Marcus contended that, if Arkla's rates are increased, its late payment revenue should also be increased and included in the revenue conversion factor. (T. 1390-1391, 1474) Arkla witness Henry asserted that, even if Arkla's rate increase is granted, no additional late charge revenue will be generated and such revenues should not be projected as a percentage of revenues and included in the revenue conversion factor. (T. 301-305) Arkla witness Harder testified that it is appropriate to follow past practices and include the uncollectible percentage in the calculation of the revenue conversion factor. (T. 166, 236-237)

AG witness Marcus acknowledged that the uncollectible percentage has traditionally been included in the revenue conversion factor. (T. 1474) Mr. Marcus has not shown that late charge payment revenues should also be included in the revenue conversion factor. This Commission historically has not included late payment revenues in the calculation of the revenue conversion factor. The AG has not demonstrated that the Commission should depart from its historical practice.

IV. CAPITAL STRUCTURE AND RATE OF RETURN

Four witnesses offered recommendations concerning the appropriate return on common equity for Arkla. Their recommendations are as follows:

Arkla witness Hadaway – 10.75% (T. 916, 940)

Staff witness Brown – 9.2% (T. 1896)

CEUG witness Staley – Maximum of 9.9% (T. 1208)

AG witness Marcus – 9.6% (T. 1371, 1459)

The required return on equity is a cost just as any other explicit expense incurred by the utility in its operation. The allowed return on equity affords the utility the opportunity, not a guarantee, to earn that return and attract capital. Additionally, the cost of equity represents a return commensurate with the returns on investments of similar risk.

In cases such as this, there are usually expert witness disagreements concerning: (1) methodology (Discounted Cash Flow ("DCF"), Risk Premium, etc.); (2) risk-comparable sample; (3) DCF growth rate; and (4) adjustments within the recommended cost of equity range. However, in this case, the three primary differences are in the DCF growth rate, the adjustment in the event Arkla-proposed Riders RSP, LCA, and/or ICR are approved, and the adjustment for Arkla's performance.

DCF Analysis

The DCF method calculates the cost of equity as

K_e = Dividend Yield + Investor-expected growth rate

In Direct Testimony Arkla witness Hadaway recommended an 11% - 11.5% DCF range for the cost of equity (T. 906) This was later updated to a 10.5% - 11% DCF range (T. 916) In both Direct and Surrebuttal Testimony Staff witness Brown recommended a DCF cost of equity range of 9.2% - 10.1% (T. 1861, 1881) Neither CEUG witness Staley nor AG witness Marcus used a DCF Method.

Since there is very little disagreement over the appropriate DCF dividend yield, the sources of disagreement are in the growth rate. Mr. Hadaway used a combination of growth rates from three sources: Zach's 5 year projections; Value Line Earnings Growth Projections from 2001-03 to 2007-09; and annual U.S. Gross Domestic Product Growth. (T. 802, 807, 825) Mr. Brown utilized four different growth rates: (1) Projected Book Value Growth and Retention Growth ("br + vs") ending 2007-09; (2) Value Line average projected growth rates for Earnings per Share ("EPS") and Book Value per Share ("BVPS") for the period 2001-03 to 2007-09; (3) Value Line average projected growth rates for EPS and BVPS for the period 2003 to 2007-09; and (4) Value Line average projected growth rates for EPS and BVPS for the period 2005 to 2007-09. We find that these four growth rates are reasonable estimates of investor-expected growth rates for usage in the DCF formula.

As discussed by Mr. Brown (T. 1871-1872), a major flaw in Mr. Hadaway's analysis is that he failed to use sustainable book value per share growth rates in gauging investor expectations. The underlying long-term and sustainable source of dividend growth rate in the DCF method is growth rate in book value per share. Mr. Brown's analysis appropriately considers that growth rate either explicitly (as in his growth rates 2, 3, and 4) or implicitly as in his "br + vs" growth rate. For that reason, we reject Mr. Hadaway's first two growth rate data sources.

With regard to Mr. Hadaway's use of the Gross Domestic Product (GDP) growth rate, he is correct that investor-expected dividend growth rates overall are likely correlated with GDP growth rate. However, he has failed to demonstrate that industry-specific DCF investor-expected growth rates are also equal to the nominal GDP growth rate. This is a crucial distinction. For example, a mature industry may have a rich dividend yield and a small expected growth rate, while a young industry may, conversely, have a small dividend yield and a large expected growth rate. It would be reasonable to expect the mature industry's expected dividend growth rate to be less than nominal GDP growth, while the young industry's expected growth is greater that GDP growth. Long-term, the three growth rates are not equal. In this case, Mr. Hadaway has failed to show that the nominal GDP growth rate has been, and is expected by investors in LDCs to be, equal to nominal GDP growth.

In both his Direct Testimony and Surrebuttal Testimony, Mr. Brown developed a cost of equity range of 9.2% - 10.1%. This is shown in his Exhibit JB-9. His four different growth rates resulted in four sample cost of equity estimates of 9.3%, 9.2%, 10.1%, and 10.0%, which results in his range of 9.2% - 10.1%. We find that Mr. Brown's DCF range of 9.2% - 10.1% is appropriate in this case.

Risk Premium Analysis

Arkla witness Hadaway was the only witness to perform a risk premium analysis. (T. 911-913, 940-942) Mr. Hadaway estimated a risk premium-based cost of equity of 10.8%.

As noted by both Mr. Hadaway (T. 1862-1863) and Staff witness Brown (T. 1874), risk premiums are not stable, and there is no one risk premium through time. An additional flaw in Mr. Hadaway's analysis is that he has relied upon risk premia studies for the S&P 500. As noted by Brown, utility stocks are perceived to be less risky than the average stock in the S&P 500. (T. 1875) For the above reasons, we conclude that Mr. Hadaway's risk premium method is not a reasonable basis upon which to set Arkla's cost of equity.

Other Cost of Equity Methods

Several parties present as evidence information on recent allowed returns for LDCs in other states (T. 837-841, 911-913, 940-942), (Hadaway Exhibits SCH-11 and SCH-12), (T. 135, 209, 234, 1888) This Commission gives no weight to such data for three reasons. First, there is an element of circularity involved if this Commission, as well as other state Commissions, rely upon rate of return determinations in other states for determining the appropriate allowed return for utilities in their states. Second, neither this Commission nor the parties have had an opportunity to probe the factors that made up the allowed return determinations in the other states. This Commission must make determinations based upon the evidence presented in testimony and hearings before this Commission, pursuant to the laws of the State of Arkansas. Third, this sort of comparison is akin to piecemeal ratemaking and is unacceptable. For example, we do not know the other state commissions' policies regarding rate base, expenses, depreciation, etc. As noted by CEUG witness Staley: "[E]very natural gas utility has different needs, different risks, different load profiles, and different performance levels. Consequently, every natural gas utility should have a uniquely determined ROE." (T. 1302)

AG witness Marcus considered expected returns on equity investments in pension plans by utilities as determined from utility annual reports. (T. 1366, 1456-1458) There are two major problems with this sort of analysis: (1) it is unclear how long the time horizon is; and (2) these returns are expected, not required. It is well-established that expected returns may be less than, equal to, or greater than required returns. For that reason, expected returns cannot be used directly as a proxy for required returns, which is the information sought in a general rate case.

Mr. Marcus also performed a Capital Asset Pricing Model (CAPM) analysis in a footnote. (T. 1371) This Commission, to date, has had two problems with CAPM analysis: the lack of stability in estimates of "beta" and the lack of stability in the market premium. Consequently, we can not rely on Mr. Marcus's CAPM analysis.

Because of the flaws identified in the risk premium and other analyses, the only reliable measure of required return on equity in the record is the DCF calculation discussed above. We will therefore utilize a DCF cost of equity range of 9.2% - 10.1% as the allowed return on equity range in this case.

Adjustment to Cost of Equity for Decrease in Risk

Staff (T. 1868-1869), CEUG (T. 1208, 1302), AG (T. 1371), and AGC (T. 1095) argue that, if Arkla proposed riders RSP, LCA, and ICR are approved, Arkla's risk would be reduced, and that a concomitant reduction in Arkla's cost of equity would be warranted. Arkla (T. 41-45) argues that Arkla witness Hadaway's and Staff witness Brown's risk-comparable group includes companies with innovative tariffs and higher customer growth that mitigate their risks. Consequently, proposed Riders RSP, LCA, and ICR do not reduce the business or regulatory risk of Arkla as compared to the risk-comparable sample, and no downward adjustment to the allowed return on equity is warranted if these Riders are approved. (T. 41-45, 927-930) Mr. Brown claimed that Arkla has several currently-effective risk-mitigating riders, Purchased Gas Adjustment ("PGA"), Weather Normalization Adjustment ("WNA"), and Main Replacement Program ("MRP"), which indicate that Arkla is not riskier than the sample. (T. 1892-1894)

As discussed elsewhere in this Order, we are not approving Proposed Riders RSP, LCA, and ICR, so that the issue of a downward adjustment in Arkla's allowed return on equity associated with approval of these Riders, need not be decided here.

External Sources of Capital in Capital Structure

Arkla witness Hadaway included three external sources of capital in Arkla's capital structure: long-term debt, preferred equity, and common equity. (T. 8837) Staff witness Brown included five sources of external capital in Arkla's capital structure: long-term debt, short-term debt, preferred equity, common equity, and customer deposits. (T. 1126) The proportions Mr. Brown's first four sources are based upon the risk-comparable sample proportions (T. 1848-1852), as are all three external components for Arkla. The primary differences between Mr. Brown and Mr. Hadaway are: (1) Mr. Hadaway developed the capital proportions using 2003 fiscal year, while Mr. Brown used 2004 fiscal year; (T. 1850) (2) Mr. Brown included short-term debt in the capital structure and Hadaway did not; and (3) Mr. Brown included customer deposits and Mr. Hadaway did not. With the exception of customer deposits, AG witness Marcus has approximately the same external capital structure proportions as does Mr. Brown.

Mr. Brown noted that short-term debt is used to fund ongoing operations and is a permanent source of capital. (T. 1850) Mr. Marcus also recommended the inclusion of short-term debt in the capital structure. (T. 1360-1361) Mr. Hadaway responded that Mr. Brown should have at least netted out the Construction Work In Progress ("CWIP") financed by short-term debt. (T. 926) Mr. Brown responded to that by noting: (1) the Commission has a long-standing position that CWIP not be included in rate base because it is not used and useful; (2) Arkla's Main Replacement Program, which is temporarily included in CWIP until those assets enter service, is effectively a monthly rate case which allows Arkla to immediately put the majority of plant additions into rates; and (3) the precedent of including short-term debt in the capital structure was specified in Order No. 13 in Arkla Docket No. 93-081-U and was followed by the Company in its two subsequent rate cases, Docket Nos. 94-175-U and 01-243-U.

This Commission is not persuaded to change its policy on the inclusion of short-term debt in the capital structure. Consequently, we will include it as recommended by Mr. Brown and Mr. Marcus.

With regard to cost rates, Mr. Brown's cost rates for long-term debt and preferred stock are more current than Mr. Hadaway's and we will adopt those. (T. 1855) Further, Mr. Brown used a current short-term debt cost rate, which we will adopt. (T. 1855-1856) Finally, no party contested either Staff's inclusion of customer deposits in the capital structure or its cost rate. Consistent with our precedent we will include those as well.

Overall Cost of Capital

For all of the above reasons we adopt Staff witness Brown's capital structure, cost of equity range, and other cost rates as shown in Surrebuttal Exhibit JB-14. In conjunction with a 9.45% allowed return on equity, discussed later in this order, this results in an overall cost of capital of 5.31%. Further, as demonstrated by Mr. Brown, his overall recommendations result in Funds from Operations interest coverage of at least 5.0, Funds from Operations to Total Debt Coverage of at least 24%, and a total debt ratio of 54%. (T. 1127-1128, 1883) Each of these financial measures meets or exceeds Standard and Poor's benchmarks for an A-rated utility with a business position of 3.

V. COST ALLOCATION

Administrative Fees of the Transportation Supply Option

Arkla witness TheBerge proposed an allocation of these revenues based on Gross Total Cost of Service. CEUG wtiness Ward recommended that these revenues be directly assigned to those classes based on actual contributions. (T. 1154) According to Mr. Ward, by reallocating operating revenues in a manner that differs from the expense allocation, an interclass subsidy is introduced. (T. 1153) However, Mr. TheBerge notes that both fees and expenses are consistently allocated across classes. (T. 639, 709) Staff, AGC, and the AG had no comments on this issue. We agree with the Company because its allocation of revenues is consistent with the allocation of related expenses.

2. Arkla is ordered to file new rates and tariffs designed in conformity with this order.[14]

3. Upon and review and approval by subsequent order, the new rates and tariffs shall become effective for meters read on or after September 25, 2005.

BY ORDER OF THE COMMISSION

This 19th day of September, 2005

Sandra L. Hochstetter

Sandra L. Hochstetter, Chairman

Daryl E. Bassett

Daryl E. Bassett, Commissioner

Randy Bynum, Commissioner

Diana K Wilson

Diana K. Wilson
Secretary of the Commission

I hereby certify that the following order issued by the Arkansas Public Service Commission has been served on all parties of record this date by U.S. mail with postage prepaid, using the address of each party as indicated in the official docket file.

Diana K. Wilson

Diana K. Wilson
Secretary of the Commission
Date 9/19/05

[14] Arkla's rates will be reduced by approximately $11.5 million.

Administration of Gas Purchases and Transportation

Arkla and CEUG recommend that these costs be allocated based on O&M. (T. 1291) The AG argues that 50% should be assigned to transportation administration, with the remainder spread by throughput to sales customers. (T. 1420-1422) CEUG witness Staley argued that it is inappropriate to charge transportation customers without crediting separate revenues to the transportation customers. (T. 1291) Staff took no position on this issue. Arkla witness TheBerge responds that it is not necessarily true that large customers require greater administration costs. In fact small customers, who tend to have low load factors, require swing contracts with special provisions. In contrast, large customers, who tend to have high load factors, have a lower need for swing or special contracts. Finally, the cost of administering gas purchases does not vary with throughput, and is not indicative of the relative cost incurred on behalf of the class (T. 622-624). We agree with Arkla and CEUG because their allocation better reflects cost causation.

Capacity-Based or Demand- Based Allocations

Arkla witness TheBerge developed a "relative demand allocation" for purposes of allocating capacity costs among customer classes. For loads that are primarily weather-sensitive, the "design-day" demand level is used. That design day is based on 59 HDD. For those loads that are not weather-sensitive, the Company used calculated winter demands. According to Mr. TheBerge, this approach captures the off-peak utilization that should bear some capacity costs. The overall relative demand level for any customer class is the sum of the two demand indicators. Finally, an adjustment was made to these two demand levels to account for overlap between minimum system analysis and cost in excess of the minimum system. (T. 494)

CEUG witness Staley disagreed with this approach for several reasons. First, off-peak consumption volumes should not be considered in any allocation of capacity costs. Second, the Company's approach does not sufficiently encourage off-peak natural gas consumption. (T. 1199) Third, a 59 HDD design day will result in demand exceeding the capacity of the Company's system. Consequently, the capacity–related costs should be based upon the curtailed coincident peak day demand. (T. 1198-1202)

Arkla witness Henry posited that the Arkla system is designed to serve a "design day" with 59 HDD and that no empirical data is provided to support CEUG's proposal. (T. 299)

Staff witness Bradley agreed with the Company's demand allocation methodology (T. 1654), while AG witness Marcus and AGC witnesses did not comment on it.

We agree with the Company and Staff since their allocation methodology better reflects cost causation. Demand-related costs are not solely incurred to meet the peak. A good portion of capacity-related costs is incurred to meet baseload and off-peak usage. For example, it could be argued that a smaller size of pipe is needed to meet that load. That is the rationale for the off-peak component in Mr. TheBerge's demand allocator. Additionally, there is an incremental component of capital associated with the peak day. That peak requires the Company to incrementally size the pipe to a greater size, above that needed for baseload or off-peak. That component is captured in Mr. TheBerge's first component. This is analogous to the Average-and-Peak Method often used to allocate production plant in electric utility rate cases, and has been previously recommended by Staff in those electric utility cases. Finally, service curtailment is a non-event for purposes of cost causation and cost allocation since curtailment is an unplanned event.

Cash Working Capital

Arkla witness TheBerge proposed that cash working capital be allocated based on O&M costs. Staff witness Bradley recommended that Accounts Receivable (Account No. 142) and the Accumulated Provision for Uncollectible Amounts be allocated based on total revenues. (T. 1623, 1648-1649) AG witness Marcus recommended that all working capital except accounts receivable, accrued revenues, and the accumulated provision for uncollectibles be allocated based on distribution property, that accounts receivable and accrued revenues be allocated based on revenues, and that the accumulated provision for uncollectibles be based on actual uncollectibles. (T. 1416-1417) AGC witness John argued that the purchased gas component of cash working capital costs should not be allocated to the LCS-1 transportation class since cash working capital costs are allegedly attributable to Gas Storage costs, and he argued that Gas Storage Costs should not be allocated to transportation customers since imbalance penalties fairly apportion gas storage costs. (T. 1075)

In Surrebuttal Testimony, Staff witness Bradley agreed with Mr. John, although she noted that he made no attempt to specifically identify the purchased gas costs allocated to the LCS-1 transportation class. (T. 1649) Mr. TheBerge agreed with Mr. John with regard to uncollected gas costs, but thought that it would be immaterial. (T. 620) CEUG made no comment on this issue.

Based on principles of cost causation, we agree with the Company that cash working capital should be allocated based on O&M, with the exceptions that accounts receivable and the accumulated provision for uncollectibles be allocated based on total revenues. However, LCS-1 transportation customers should be allocated gas storage, any purchased gas costs included in Staff's MBSA should be allocated to the LCS-1 transportation customers consistent with our decision that LCS-1 transportation customers should be allocated gas storage.

Cost Classification and Cost Allocation of Distribution Mains

The largest single investment in the Company's distribution system is its distribution mains. This Commission historically has considered distribution mains as having a customer-related portion and a capacity-related portion. This assumes that there is a zero- or minimum size necessary to connect the customer to the distribution system. Considering the magnitude of the distribution mains account, the classification and allocation of distribution mains has a significant impact on the cost of service. The heart of the issue is separating the customer-related function from the capacity-related function.

To gain some perspective on the importance of this issue we refer to Arkla Exhibit MT-60. As shown there, the net distribution main plant is approximately $165 million, according to Arkla's Sur-Surrebuttal case. As shown in Table 4 of Staff witness Bradley's Prepared Testimony, she recommends that 62.30% of the distribution main costs be classified and allocated to the Residential Class, with 37.70% classified and allocated to the Small and Large Commercial Classes. In contrast, Arkla proposes that 78.62% of the distribution main costs be classified and allocated to the Residential Class with 21.38% classified and allocated to the

Small and Large Commercial Classes. The amount of rate base in play is then (78.62% - 62.30%) X $165 million = $27 million. This does not include other cost categories that may be affected by this classification.

There are two generally-recognized methods for determining the customer-related portion of distribution mains: the zero-intercept method and the minimum size method (T. 1616-1617) and Gas Distribution Rate Design Manual, National Association of Regulatory Utility Commissioners, (Washington, D.C., January, 1989), p.22.) The zero-intercept method involves performing a statistical ordinary least squares regression of main cost (as the dependent variable) on main size (as the independent variable). The resulting positive-valued Y-intercept represents the cost of a main with a size of zero. This cost amount is then considered the "customer cost", with the remaining portion representing capacity costs.

The minimum-size method involves the determination of the "minimum size" main on the system and pricing out the entire length of system distribution mains at the historical cost of this minimum size main. This is considered customer-related, with the remaining portion of distribution main costs considered capacity-related. While the zero-intercept method, with reliable data, estimates the customer costs associated with a zero-size pipe, the minimum-size method may include some capacity costs since any minimum size pipe considered will be strictly greater than zero. (T. 666, 1617)

Arkla witness TheBerge uses a minimum size method with 2" pipes. He considered two constraints in determining this size. The first constraint is that the minimum pipe size should reflect the least amount of theoretical capacity. The second constraint on the pipe-size selection is presence within the Mains account at a representative level; that is, the pipe size should have a sufficient footprint within the Mains account to reflect original installation costs under a variety of physical conditions and economic circumstances throughout Arkla's 65-year time period. He concluded that a 2" pipe best meets these criteria. This resulted in a 70.54% classification to customer-related and a 29.46% classification to capacity-related.

Relying on engineering studies, Mr. TheBerge determined that the 2" pipe on Arkla's system did contain some level of capacity, approximately 2.5 cubic feet per hour. For adjustment purposes he used 5 CFH, and used this to adjust the design day levels of demand for each customer class.

Staff witness Bradley testified that the Staff prefers the zero-intercept method because, even with the smallest size pipe on the system, customer–related costs are overstated since some material costs are included. (T. 1617) However, because of issues of data integrity associated with the Company-supplied data necessary for the zero-intercept method, she opted to use the minimum size method. (T. 1618) Ms. Bradley argued for three criteria for determination of the "minimum size": (1) the appropriate pipe size for the minimum size study is in fact the minimum size; (2) the minimum size pipe should be present in a variety of locations throughout the distribution system; (3) the minimum size should have been installed throughout the service territory. (T. 1620) In particular, she noted Tables 4 and 5 in her Surrebuttal Testimony, p. 13, which show the dispersion, through time and across Arkansas counties, of 1" Mains.

Based on these criteria Ms. Bradley concluded that the 1" pipe meets the criteria and used that size in her minimum size study. That resulted in her classification of approximately 24.3%

of the Company's investment in distribution mains as customer-related, with the remaining portion, 75.7% classified as capacity-related. (T. 1646) Arkla witness TheBerge argued that the 1" pipe did not meet her criteria (2) and (3). (T. 665-669)

AG witness Marcus used three approaches for classifying and allocating distribution mains: (1) the peak and average method; (2) the zero-intercept method; and (3) the minimum connection method. The peak and average method assigns no distribution main costs as customer-related, but instead assigns them to commodity (throughput) related and capacity (demand) related. The amount assigned to commodity is equal to the load factor [(volume /8760 hrs.[9])/coincident peak], which in this case was calculated by Mr. Marcus at 22.48%. The remainder, 77.24% was assigned to capacity. (T. 1407) Mr. Marcus then allocated the commodity component to classes based on a volumetric allocation factor, and the capacity component was allocated based on peak demand allocation factors. Arkla witness TheBerge argued that if the peak and average method is used here, it should be distance-weighted. (T. 576-577)

Mr. Marcus used Company-provided data (Response to AUD-061) for the zero-intercept method and determined that 24.08% of distribution main costs are customer-related with the remainder classified as capacity, or demand, related.

Under Mr. Marcus' minimum connection method, he assigned 56 feet of two inch main per customer as a customer cost. He believes that that is the minimum amount of main required to connect a medium-sized customer to the system. With that method, he determined that 24.2%

8,760 hours represents the number of hours in a year.

of distribution main costs are customer-related. (T. 1407-1413) Arkla witness TheBerge disagreed with the 56 feet method used by Mr. Marcus, and argued that a reasonable minimum-connection should classify no less than 108 feet as customer-related. (T. 583-587)

CEUG witness Staley endorsed the Company's 2" minimum-size method with one modification: off-peak customers should be excluded from calculation of the "design day" demand day. (T. 1279)

AGC witness John recommended that an average of the costs of 2" and 4" mains be used to determine customer-related costs. He asserted that large customers are not typically served by 2" mains and that 4" mains are used to serve some residential customers. This approach results in customer-related costs of 85.19% and capacity-related costs of 14.81%. (T. 1081-1083)

In support of his analysis Mr. John provided his Gas Main Study. (T. 912, 927, 1112-1116) In essence, this study attempts to ascertain the embedded cost of a stand-alone mains system for the LGS-1 class. That study allegedly demonstrates that a physical analysis of the pipes in the ground serving the LCS-1 class is comparable in costs to the classification and allocation method used by AGC.

Staff witness Bradley responded to this analysis by arguing that (1) some customers receive gas from more than one point of receipt, depending upon operating conditions; (2) some customers are located on a part of the distribution system where the gas travels more than one path and route; (3) all Arkla customers in the state are served by all gas mains; and (4) because the mains are common facilities, there is no way to determine if one particular gas main is dedicated to one particular customer. (T. 646-648)

In consideration of all of the testimony, exhibits, and studies presented to us by all of the parties, we adopt the Staff allocation since it better reflects cost causation.

During cross-examination, CEUG's counsel made much of the prevalence of the 2" main size on the system, relative to the 1" main size. (T. 651-652) But that argument misses the point. The minimum size method seeks the smallest size main given the constraint that the main size is a representative price proxy. While the 2" main would provide a representative proxy, it would abysmally fail the "minimum-size" test. Entirely too much of the cost of a 2" pipe is associated with providing capacity.

As shown in Staff witness Bradley's Table 4, the 1" main has been used over the 1939-2004 time period. Because of that wide dispersion in installation dates, the use of a 1" main is fairly representative of the embedded customer costs, *without* upward bias due to a preponderance of later installations, or downward bias because of a preponderance of earlier installations. This bias can occur for two reasons: (1) later installations cost more because of inflation; and (2) later installations are not as depreciated as earlier installations. A good example of that potential bias was provided in a discussion with the Commission on the merits of using the absolute smallest pipe size (0.5" in.). That size has only been installed since 1999, and would not be representative of the system across time and location. (T. 671-673)

Additionally, the 1" pipe has been installed in 93% of Arkansas counties in Arkla's service territory, as shown in Ms. Bradley's Surrebuttal Table 5, and in 15,000 records in the Arkla database provided in Response to Staff data request AUD 061. (T. 656) Geographical dispersion is important in the evaluation of representation since Arkansas has a wide variety of geographical landscapes, which will have an influence on the costs of any given pipe size. (T. 657) The 1" pipe was installed in a variety of these landscapes. (T. 657)

Consequently, the 1" pipe does a reasonable job of meeting the minimum-size criterion while also being a representative price proxy (representative across time and geographical landscape), while the 2" and 4" pipe sizes do not meet the minimum-size criterion.

Although the Company attempted to remove any related capacity costs in the 2" main cost, the basis for that adjustment is not useful for this case. First, the engineering study upon which the adjustment was based was developed for another case. Second, the study does not represent the Arkla service territory. (T. 659) As noted by Ms. Bradley, it is more efficient to go directly to a representative size pipe, 1", rather than to follow the circuitous route of using an above-minimum size pipe, 2", and then attempting to adjust capacity costs out of it. (T. 659)

We also note that AG witness Marcus performed a zero-intercept regression analysis that was supportive of Ms. Bradley's classification of 24.3% of distribution main costs as customer-related. Mr. Marcus' regression results indicate a customer-related classification for distribution mains of 24.08%. (T. 141)

With regard to AGC's Gas Main study, we agree with Staff witness Bradley's assessment of the difficulty of accurately ascertaining the stand-alone costs of serving a particular customer class on a network system with common costs. Further, the Commission notes several analytical errors in the AGC study. Primary inputs to that study are the estimates of unit cost per foot of main across the Arkla system, shown in Arkla Rebuttal Exhibit MT-43. Those unit costs per foot are used by AGC to estimate individual customer main costs in Protected Exhibit AGC-10.

There are two problems with the application of this data to the AGC Gas Mains Study. First, the unit costs for many of the main sizes are anomalous. One would expect that as the size of the pipe increases, the unit cost per foot would increase. That is simply not the case: (1) 1.5" pipe has smaller unit cost per foot than does 1" pipe; (2) 2.5" pipe has smaller unit cost per foot than do 1.25" pipe and 2" pipe; (3) 3.5" pipe has smaller unit cost per foot than do 2" pipe and 3" pipe; (4) 4.5" pipe has smaller unit cost per foot than do 3" pipe and 4" pipe; (5) 7" pipe has smaller unit cost per foot than do 2" and 6" pipe; (6) 8" pipe has smaller unit cost per foot than do 6" and 7" pipe; (7) 16" pipe has smaller unit cost per foot than does 12" pipe; and (8) 20" pipe has smaller unit cost per foot than do 6", 10", 12", 16", and 18" pipe. We are not saying that the actual calculations of the unit costs per foot are in error. It is just that the data is not useful for purposes of the AGC Cost Study. It is likely that the reason this occurs is because many of these unit costs per foot are not representative across time and geographical location.

A second problem with the AGC Gas Mains Study is that the analysis does not focus on the costs at a particular LGS-1 customer location. These unit cost estimates are based on the *average* across the Arkla system.

Finally, the AGC Gas Mains Study uses an average 41% Accumulated Depreciation factor to adjust gross plant to net distribution mains plant. Again, this factor is Arkla *system distribution wide* and is not specific to the accumulated depreciation at a particular LGS-1 customer's location.

Given these three analytical flaws in the AGS Gas Mains Study and the common plant point raised by Ms. Bradley (T. 646-648) we give very little weight to the AGC Gas Mains Study.

Ms. Bradley also recommended that Arkla be required to accumulate and maintain the data necessary to properly perform the zero-intercept method. She stated that both linear and non-linear regression analyses can be run, that both Arkansas Western Gas and Arkansas Oklahoma Gas currently accumulate and maintain data for the zero-intercept method, and that it is unlikely that the additional data accumulation would be at great cost. Further, she recommended that the Company be required to accumulate and maintain the following data necessary to perform a zero-intercept study in the future: (1) authorization for expenditure or job number; (2) code identifying the type of material, e.g. plastic, steel, cast iron, and a number identifying the size of the pipe in inches; (3) number of units, e.g. footage for pipe, count for fittings and valves; (4) cost of materials; (5) cost of labor; and (6) cost of overhead. (T. 1618, 1646-1648)

The Commission agrees with Staff witness Bradley's recommendation, and hereby directs Arkla to begin accumulating the necessary data for performing a valid zero-intercept regression method. We do not agree with the Company that having non-linear data will automatically invalidate the zero-intercept method; the appropriate solution is to perform a non-linear regression. At this time we are not pre-judging whether such analysis should be linear or non-linear, but note that there are numerous statistical packages that can do either.

Customer Accounting and Sales Expenses (Account 916)

The Company and CEUG recommend that Customer Accounting be allocated based on unweighted customer counts. (T. 1289-1290) The AG recommends that weighted customer information be used because it is more complex to read meters and provide service to large customers. (T. 1418) CEUG witness Staley testified that there is no evidence to support that claim and that, based on his experience, it is less complex and less costly to read the meters of larger customers. The Company and CEUG recommend that Account 916 be classified and allocated based on the number of customers. The AG recommends that 90% of the costs in Account 916 be directly assigned to transportation customers and 10% assigned to the LCS class. (T. 1419) Staff and AGC did not comment.

We agree with Arkla and CEUG because their allocation better reflects cost causation.

Customer Allocation Factors

Arkla witness TheBerge proposes a customer allocation factor based on the number of current fixed installations for each customer class. (T. 494, 691-692) Staff witness Bradley recommends that those allocations be based on normalized customer counts. (T. 1623) Neither the AG, AGC nor CEUG made comments. We agree with the Staff since its allocation more reasonably reflects ongoing conditions.

Distribution Load Dispatching

The Company and CEUG propose that Distribution Load Dispatching be classified as both customer- and capacity-related, and allocated accordingly. (T. 519, 1288) Staff witness Bradley proposes that this account be classified solely as capacity-related and allocated accordingly. (T. 1648) AG witness Marcus proposes that this Account 871 be classified as 9% directly to transportation administration, and 45.5% be classified and allocated to capacity and throughput each. (T. 1417-1418). We agree with Staff witness Bradley since these facilities are used in dispatching gas and thus do not have a customer-specific component, and are entirely capacity-related.

Gas Storage Inventory

Arkla and Staff propose that gas storage inventory be allocated based on demand. (T. 608, 1653) AG witness Marcus recommends that the allocations be based on 45.6% by sales to sales customers and 55.6% by peak demand to all customers. (T. 1490) Further, Mr. Marcus recommended a 35-65 commodity/demand split. (T. 1490) AGC witness John recommended that no gas storage inventory costs be allocated to the LCS-1 transportation class. (T. 1074-1075, 1120) Mr. John also notes that Section 3.21.1 of the LCS-1 Rate Schedule provides that Transportation Supply Option ("TSO") transactions are not allocated any storage costs. (T. 1119) CEUG witness Ward proposes that no gas storage inventory be allocated to TSO since the Company's balancing provisions for TSO customers protect those supply-related assets by imposing significant penalties for excessive imbalances. (T. 1154-1156) Consequently, according to AGC and CEUG, those imbalance penalties already fairly apportion gas storage costs to transportation customers.

We agree with the Company and Staff since their proposed allocation better reflect cost causation. Gas storage brings significant operational benefits to the on-system operation of the distribution grid. Arkla's allocation of gas storage inventory is designed to recognize the continuous minute-to-minute pressure balancing required for both sales and transportation customers. (T. 568-569, 594) Storage service is a prerequisite for load-following service, which benefits sales and transportation customers. Additionally, the imbalance fee recovered from transportation customers is significantly less than the cost of the imbalance fees that would be associated with load-following services provided to stand-alone transportation customers. (T. 576, 703) A relative demand allocation best meets the cost causation principles for gas storage as noted in the Rebuttal Testimony of Arkla witness TheBerge: (1) storage is used to meet peak-day demand; (2) storage is able to meet downstream load-following service based on load-following receipts upstream; (3) storage is used to meet periodic imbalances; and (4) storage is used to capture and transfer methane prices between seasons. This last function is properly reflected in the GSR mechanism in the form of methane costs that are allocated based on sales volumes. (T. 709)

Land and Land Rights and Structures and Improvements

Arkla witness TheBerge argues that Land and Land Rights and Structures and Improvements, Accounts 374 and 375, should be allocated based on the classification and allocation of distribution mains. Staff witness Bradley recommends that they be classified and allocated based on all facilities on the grid, Accounts 376, 378, and 389. (T. 1623) AG, AGC, and CEUG did not comment on this issue.

We agree with the Staff since its allocation better reflects cost causation. As noted by Mr. TheBerge, items recorded in Account 374 are the cost of owning, leasing, or accessing the land occupied by the distribution mains *and* other components of the grid. (T. 510) Also, items recorded on Account 375 represent investment primarily required for the support of the Company's *distribution system networks*. (T. 510) Since those accounts support the distribution grid, generally, Staff's allocation is more reasonable.

Measuring and Regulating Station Equipment

Arkla witness TheBerge recommended that Accounts 378 and 379, Measuring and Regulating Equipment, be allocated based on the allocation of Distribution Mains, Account 379. (T. 595-598, 686-691) Staff witness Bradley argued that those amounts should be classified as capacity–related and allocated based on demand (T. 1623), while AG witness Marcus recommended that they be classified as capacity-related and allocated based on a peak and average method or some form of a minimum system analysis that excludes the customer portion. (T. 1413-1414, 1484-1485) Neither AGC nor CEUG commented on this issue.

We agree with the Staff since these facilities are used in measuring and regulating gas and therefore do not have a customer-specific component and are entirely capacity-related. As noted by Ms. Bradley: "Measuring and regulating equipment would not exist if gas were not being delivered. Again, customer-related costs pertain to having access to the distribution system, not the delivery of gas." (T. 567)

Meter Installations

Arkla allocated Meter Installations, Account No. 382, based on the cost of meter installations used to serve each customer class. AG witness Marcus argued that the Company incorrectly applied sales tax and purchasing and warehousing overheads. (T. 1414-1415) Arkla witness TheBerge agreed but noted that Mr. Marcus then introduced a new error in removing the excess from the replacement-cost-new level exclusively for the residential class instead of all of the classes. (T. 598-599) Correcting for that results in the Company-revised allocations shown on p. 51 of Mr. TheBerge's Rebuttal Testimony. Mr. Marcus agreed with those corrections. (1483) We agree with those revised allocations.

Other Operating Revenue

The Company and CEUG propose that tariffed charges such as late payments, returned checks, service establishment, collection, reconnection, etc., be allocated based on gross margins. In particular, CEUG witness Staley notes that the allocations of revenues and expenses should be applied consistently. (T. 1223) AG witness Marcus proposes to assign these based on the classes who pay the charges. (T. 1423) Staff and AGC did not comment on this issue.

We agree with the Company and CEUG since their allocation better reflects cost causation. Many of these charges are simply penalties which are designed to discourage specific behavior and, consequently, have no class-specific entitlement. (T. 629) With regard to the other charges, since they are not being redesigned in this proceeding we do not know their specific cost components. Further, many of the charges are the product of earlier proceedings including settlements. (T. 629-630)

Regulatory Commission Expense

Arkla and CEUG propose that Account 928, Regulatory Commission Expense, be classified as customer-related and allocated based on customer counts. (T. 1289-1290) Staff and the AG argue that it should be classified as revenue-related and allocated based upon revenues. (T. 1419-1420, 1629-1637) AG witness Marcus also specifies that 75% of these costs be allocated by gross margins and 25% allocated by gas sales revenues. CEUG witness Staley responds by saying that many of the contentious issues in this rate case have significant effects upon all of the rate classes, not just the large customers. (T. 1289-1290) CEUG argues that the AG's position should be rejected. AGC did not comment on this issue.

We agree with the Staff and the AG that revenue allocations better reflect cost causation in this case. As discussed by Arkla witness TheBerge in cross-examination, he has used a revenue allocator for this cost item in other cases. (T. 595-596) However, he is concerned about the potential circularity involved in allocating this item based on revenue, or cost of service. We do not see such circularity. A straightforward way of accomplishing this allocation is to allocate Regulatory Commission Expense based on the final cost of service, excluding Regulatory Commission Expense. It is a simple matter of arithmetic to show that after that allocation, and inclusion in the cost of service, the equivalent allocation results are produced. Given the relatively small size of this expense in the revenue requirement, class revenues are a good proxy for class cost of service.

Services, Meters, Meter and Regulator Installation, House Regulators, Individual Measuring and Regulating Equipment

Arkla witness TheBerge recommends that Accounts 380-385 be classified as customer and capacity-related and allocated based on point-in-time customer locations. Staff witness Bradley recommends that these be classified as entirely customer-related and allocated based on normalized customer counts. (T. 1623) The AG, AGC, and CEUG had no comments on this issue. We agree with Ms. Bradley since its allocation better reflects cost causation. These items are strictly customer-related and have very little, if any, demand, or capacity-related, component.

Telemetering Costs (A&G Accounts 920 and 921)

Arkla and CEUG propose that telemetering costs be allocated based on O&M expenses. (T. 1290-1291) AG witness Marcus argues that all of telemetering costs be directly assigned to LCS-1 customers, with an adjustment to rate base for Account 902 to prevent overlap. (T. 1420) CEUG witness Staley argues that it is inequitable to charge LCS-1 customers without crediting them with separate revenues. (T. 1290-1291) Staff and AGC did not comment on this issue. We agree with Arkla and CEUG since their allocation better reflects cost causation.

VI. RATE DESIGN

Class Rates of Return

Arkla and Staff recommend that all classes pay equivalent rates of return. This is consistent with the principle that each class should pay its Cost of Service. (T. 649-650, 1614, 1655) Arkla's Cost of Service Study indicates an approximate 10% increase for the Residential Class, a 2% increase for the SGS Class, and a 0.13% increase for the LGS Class.

Using Staff's Cost of Service study, the net result would be approximately a 4% decrease for the Residential Class, a very slight 0.3% increase for the SCS Class, and a 7% increase for the LGS Class. In designing rates once the revenue requirement is decided upon, Staff witness Bradley emphasized the principles of gradualism and stability; rate design should minimize adverse impacts while providing the Company with a reasonable opportunity to recover its approved revenue requirement. (T. 1625, 1657).

AG witness Marcus asserted that cost studies should be treated as guidelines, that differentials in class rates of return may be justified by risk, and that a cost study's results must be balanced with other ratemaking and public policy goals of the Commission. Examples of the latter are avoidance of rate instability and giving customers control over their bills. (T. 1396-1399, 1425) In Supplemental Surrebuttal Testimony, Mr. Marcus proposed assigning all of the decrease in rates to the Residential Class, and freezing the Commercial Classes at current rate levels. (T. 1448) This would have the effect of the Residential Class having a greater rate of return than the Commercial Class, based on the AG's Cost of Service Study.

AGC witness John argues that AGC customers should be appropriately assigned their costs in rate design. (T. 1083) CEUG took no position on the issue.

Generally speaking the Commission agrees with the concept of equal rates of return as recommended by Staff. Adopting equal rates of return in rate increase cases has been the norm for the Commission for a number of years. However, given that the net result of this order is a substantial rate decrease, and given that Staff's rate design proposal would mean a slight increase for the small commercial class and a significant rate increase for the large commercial class while decreasing rates only for the residential class, the Commission finds that it is more appropriate to deviate somewhat from Staff's rate design proposal. For purposes of this rate case the Commission finds that the rates for the small commercial class and the large industrial class should be held constant and the rates for the residential class should be decreased accordingly.[10]

Residential Class Rate Design

Arkla proposes that the customer charge for the RS-1 class increase from $9.75 to $17.00. The Company proposes to decrease the amount of usage applicable to the first block from 50 CCF to 15 CCF, increase that block's charge from $0.2630 to $0.8267, and decrease the second block from $0.1847 to $0.0572

Staff witness Bradley opposed those changes because they will, taken together, significantly increase the minimum charge to many residential customers. (T. 1625-1627) As shown in Table 7, p. 19, of her Prepared Testimony, that increase may be as high as 114.7%. Given the principle of rate stability, she believes that a rate increase of this magnitude would have a significantly adverse impact. (T. 1626) Ms. Bradley recommended that the Residential Class pay its cost of service, that the RS-1 customer charge rate remain at the current level, and that the residential rate decrease, based on Staff's cost of service (T. 1634), be accomplished by reducing the rates applicable to the second block. (T. 1627, 1658)

AG witness Marcus claimed that under virtually any method for classifying distribution main costs, with the exception of Arkla witness TheBerge's, the RS-1 class is paying above the system average. (T. 1426) Further, Mr. Marcus does not believe that complete equalization of rates of return is required. (T. 1427)

Mr. Marcus recommended that the current rate structure be maintained for all rate classes, including RS-1. Further, he proposeed that the RS-1 customer charge remain the same, and that any rate increases for the residential class occur in both volumetric blocks. In support of

[10] The application of equal rates of return would mean that the residential class would receive a rate decrease of approximately 4.04%. Taking into consideration the Commission's findings on rate design, the residential class will

this, he noted that the customer impacts of Arkla's proposal may be extreme. (T. 1429-1434) He asserted that this major increase in the customer charge reduces shareholder risk dramatically. (T. 1428)

Mr. Marcus claimed that the increase in the customer charge would have disproportionate impacts on lower-income people since the proposal would primarily impact low usage customer, and lower income people use less gas than higher income people. (T. 1430-1431) He cited five studies to support this hypothesis. First, he performed a regression analysis using Arkansas zip codes, which showed that people in upper-income areas use more gas than the average customer. (T. 1431) Second, he ran another regression on Arkansas counties, which showed that in 2003 usage per customer was 472 CCF plus 11 CCF per $1,000 of income. (T. 1431) Third, he presented data from the Bureau of Labor Statistics that show a positive correlation between income level and natural gas usage in the southern region of the U.S. (T. 1431) Fourth, he relied upon data from the Energy Information Administration, which indicates that a family over the $50,000 income level uses 36% more natural gas than the average family under the poverty line. (T. 1432-1433) Fifth, he conducted a study using survey data from Pacific Gas & Electric that shows that lower income customers use considerably less gas than higher income customers. (T. 1433)

Arkla witness TheBerge claims that its proposed residential rate design will result in smaller bills for many underprivileged customers, particularly in east Arkansas. This is because many of those customers have poorly insulated homes. (T. 679-680) Mr. TheBerge also noted that all of the studies that he has seen indicate that there is not much difference in usage between

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receive a rate decrease of approximately 3.54%.

lower-income and upper-income customers. (T. 687) In response to a question from the Commission, Mr. TheBerge stated that the average residential customer uses 54 CCF per month and would see a $3.20 per bill increase under the Company's proposal. (T.723) He also stated that 4 counties in east Arkansas with below average incomes have above average consumption of natural gas. (T. 724)

CEUG did not directly address RS-1 rate design. AGC witness John indirectly addressed RS-1 rate design in that he has concerns that the LCS-1 class is subsidizing the other classes. (T. 1084-1086)

We agree with both Staff and the AG that Arkla's proposed rate design for the RS-1 class would have severe rate shock impacts on many residential customers, especially lower income customers. We agree that the Residential Class should pay its cost of service, that the RS-1 customer charge rate should remain at the current level, and that the residential rate decrease from Staff's cost of service should be accomplished by reducing the rates applicable to the second block.

Residential Customer Survey

AG witness Marcus proposed that Arkla conduct a study of its customer base, in particular with regard to gas usage, economic factors, and demographic factors. He claimed that there is a paucity of data regarding the impacts of various rate designs. He recommended that this Commission authorize $150,000, amortized over three years, in this rate case to be spent by Arkla on such a study. (T. 1435-1436)

We agree with his proposal and authorize an additional $50,000 in expenses for this project. The study should be comprehensive and include factors such as those listed in Mr. Marcus Direct Testimony, p. 91.

Small Commercial Class Rate Design

Arkla witness TheBerge proposes that the customer charge for the SCS-1 class increase from $13.00 to $18.00. In addition, Mr. TheBerge proposes an increase in the SCS-2 (Off-Peak) first 1500 CCF block rate from $.1817 to $.2060. Mr. TheBerge proposes that the Gas Supply Rate ("GSR") charges for the SCS rate class be set on a volumetric basis, instead of the current demand based billing. (T. 276) Arkla witness Henry proposes this change because of the significant increase in customer complaints after the initiation of the new SCS rates in September, 2002. (T. 276) As noted by Mr. The Berge, the volumetric rate design works well for the majority of the SCS Class because the the customers in this class are predominantly low-load factor customers. (T. 839) Mr. Henry also proposes the elimination of the SCS-2 true-up mechanism. Instead, over- and under-recoveries would be recovered from all SCS customers.

Staff witness Booth agreed with the change to volumetric billing for the GSR rate in the SCS class for the same reason as the Company. (T. 863-864, 1751) However, Mr. Booth opposed the elimination of the true-up mechanism for the SCS-2 class because it is appropriate for the SCS-2 customers to pay the costs of providing service to them and it is inappropriate for those costs to be spread to other SCS customers. (T. 1753) Staff witness Bradley opposed the increase in the SCS customer charge because it will significantly increase the minimum charge to many SCS customers. (T. 1625-1627) She recommended that the SCS class pay its cost of service, and that, because of the minimal change in the SCS class cost of service, this class increase occur entirely in the customer charge. (T. 1634, 1658)

CEUG witness Staley recommends that the Company-proposed increase in SCS-1 fixed costs be reduced. (T. 1209) Further, Mr. Staley opposed the recovery of GSR charges on a volumetric basis and recommended continuation of the current demand based billing. (T. 1211-1212) Mr. Staley noted that a change from demand-based to volumetric billing in the GSR rate would be confusing and would restore a subsidy among sales customers. (T. 1222) Additionally, Mr. Staley pointed out that many customers now have equipment that can accurately measure demand. (T. 1306) Even if the GSR rate is not maintained as a demand-based billing component, a volumetric GSR rate should be of the declining block type. (T. 1222)

AGC witness John indirectly addressed SCS rate design in that he has concerns that the LCS-1 class is subsidizing the other classes. (T. 1084-1086) The AG did not comment on the SCS class rate design.

We agree with Staff that the only change in the SCS class should be a slight increase in the customer charge and that the SCS class should pay its cost of service. Further, the change to volumetric billing for the GSR rate is appropriate because of the prior customer confusion. We also agree with Staff that the true-up mechanism should stay solely within the SCS-2 subclass.

Large Commercial Class Rate Design

Arkla witness TheBerge proposes a decrease in the LCS-1 customer charge from $290 to $26. Further, he proposes a flat demand charge of $3.38/MMBtu for all MMBtus (one-step) rather than \$5.5790/MMBtu for the first 400 MMBtu and \$.400 for all MMBtu over 400 (two-step). The LCS-1 rate changes are proposed to be delayed until November 1, 2006.

Staff witness Bradley recommended that the current structure be maintained by increasing each current charge equally. (T. 1627) Ms. Bradley expressed concerns that Arkla's LCS-1 rate design proposals may cause some customers to experience increases of more than 70%. (T. 1657)

AG witness Marcus recommended that no change to the LCS transportation administration fee be made. (T. 1495)

CEUG witness Staley recommended that the LCS-1 class retain its declining block rate and that any proposed increase or decrease in this class be accomplished by increasing or decreasing each tier demand charge equally. (T. 1211, 1312)

AGC witness John agrees with Staff witness TheBerge's proposed one-step rate design, but noted that since that rate design, if approved, would reduce Arkla's business risk, the Commission should reduce Arkla's allowed return on equity. (T. 933, 1083-1084, 1129-1130) He disagreed with a two-step declining block demand charge because it will result in intra-class subsidies.

CEUG witness Ward and AGC witness John also proposed that the LGS class be divided into a transportation class and a sales class because the underlying characteristics of sale customers and transportation customers are different. In particular, sales customers receive a "bundled service", and transportation customers are governed by the balancing provisions of the LCS-1 tariff. Additionally, separating sales and transportation customers would help ensure that purchased gas and administrative costs are more easily tracked and allocated. (T. 1087-1088, 1130)

Arkla witness TheBerge claimed that the nature of distribution service provided to sales customers and transportation customers is essentially the same. This is evidenced by the historical conversions back and forth between the two. He also noted that separate schedules will not facilitate revenue or expense tracking because the Company is not constructed, organized, managed, or operated based on rate schedules. Additionally, cost allocation models will be no less complex. (T. 710-713) No other party addressed that issue.

We agree with Staff witness Bradley's proposal that the current LGS-1 rate structure be maintained by increasing each current charge equally and that the LGS class pay its cost of service. Further, we agree with the Company that there should be no split between transportation customers and sales customers. In the past few years, Arkla's rate Schedules have been simplified. We do not intend to reverse that course and go down the path of increasing complexity.

VII. RATE RIDERS

Rate Stabilization Plan

In its filing, Arkla proposed a new Rate Stabilization Plan ("RSP"). This RSP would provide for the review and, if necessary, adjustment of rates on an annual basis. Under the Company's proposal, earnings would be evaluated annually based on a test year ending April 30 with rate changes to take effect on October 1. For purposes of determining earnings, net income would be based on actual results adjusted for: weather normalization; gas cost normalization;

wage, salary and benefit increases effective at the end of the test period ending April 30; tax rate and assessments and other items of expense at the end of the test period or which are established by contract or government action for the 12 months beginning May 1; and interest synchronization. (Application Vol. II, Schedule J, p. 7.)

To determine whether a rate adjustment is necessary, Arkla has proposed that a 100 basis point deadband around the allowed return on equity ("ROE") be established. To the extent that its earned ROE is more than 50 basis points below the allowed ROE, rates would be increased by the amount necessary to generate the revenues necessary to increase the earned ROE to the allowed ROE. If the earned ROE exceeded the allowed ROE by more than 50 basis points but not more than 150 basis points, Arkla would refund 50 percent of the excess earnings in excess of the 50 basis point deadband. To the extent the earned ROE exceeded the allowed ROE by more than 150 basis points but not more than 250 basis points, an additional 75 percent of the earnings in the excess of 150 basis points would be refunded. Finally, if the earned ROE exceeded the allowed ROE by more than 250 basis points, Arkla would refund 100 percent of the earnings above the 250 basis point threshold. (Application Vol. II, Schedule J, pp. 2-3.)

Both the Staff and the AG urge that the RSP be rejected. Staff witness Booth noted that the Commission has historically elected to approve riders such as the RSP only where doing so resulted in an equitable balance of the interest of the Company and its customers. Mr. Booth argued that the claimed benefits of the RSP, avoidance of regulatory lag and reduced rate case expense, do not warrant a departure from traditional ratemaking practices. He also testified that the RSP does not satisfy the criteria applicable to the evaluation of automatic adjustment clauses.

Those criteria are: (1) the RSP does not apply to a cost element that represents a significant portion of the utility's total operation costs; (2) the costs do not exhibit extreme volatility and unpredictability; and (3) the cost item is not outside the control of the utility's management. (T. 1740-1744)

AG witness Marcus argued that the RSP is one-sided in that it protects the Company from all risk on the downside, but only results in a small sharing of the upside risk. He further pointed out that the RSP is one-sided in that it provides permanent rate increases when earnings shortfalls occur. However, when earnings surpluses arise, one time bill credits or refunds are given for a portion of the excess. He noted that while performance based regulation mechanisms have been given greater consideration in recent years, Arkla's proposed RSP does not qualify as performance based regulation. (T. 1354-1358)

In his Rebuttal Testimony at page 88, Arkla witness Harder argued that the Commission has the discretion to depart from traditional ratemaking policies and procedures to approve a rider such as the RSP. He argued that there are additional benefits that the Staff ignored, including more closely aligning rates with costs and capping the Company's ROE at 1.25 percent above the Commission approved ROE. (T. 94) Mr. Harder argued that those benefits, in combination with reductions in rate case expense and regulatory lag, warrant departing from traditional ratemaking.

As noted by Staff witness Booth in his Prepared Testimony, (T. 1743) the Commission addressed a similar proposal (called the Rate Evaluation Plan or REP) by Arkla in Docket No. 93-081-U. In Order No. 13 in that docket, the Commission found that the REP did not meet the criteria historically used in evaluating automatic adjustment clauses and it rejected that proposed rider. In this case, the RSP is rejected for the same reasons. Those are: (1) the RSP does not apply to a cost element that represents a significant portion of the utility's total operation costs; (2) the costs do not exhibit extreme volatility and unpredictability; and (3) the costs addressed by the RSP are not outside the control of the utility's management. We do not agree that the benefits identified by Arkla satisfy the criteria that would warrant a departure from traditional ratemaking policies and procedures and justify the implementation of the RSP.

We also agree with the concerns raised by AG witness Marcus that the RSC is one-sided in favor of the Company and investors. When earnings are below the proposed deadband, or more than 50 percent basis points below the allowed ROE midpoint, revenues would be increased by an amount necessary to bring the earned ROE back to the midpoint or allowed ROE.[11] In contrast, when rates are above the upper end of the deadband, or more than 50 basis points above the allowed ROE, the Company would refund only a portion of the excess over the upper end of the deadband. Moreover, because rates themselves are not changed, Arkla would be left with the potential to over-earn again the following year. Accordingly, we reject the RSP.

Infrastructure Cost Recovery (ICR) Rider

Arkla witness Harder states that the purpose of the ICR Rider is to replace the existing Main Replacement Program ("MRP") Rider as the primary mechanism to fund the cost of the cast iron and bare steel replacement program between general rate cases. Mr. Harder contends that the ICR Rider, when used with the LCA Rider, would mitigate Arkla's need to file rate cases

[11] It is noted that this provides the incentive to increase expenses if earnings would otherwise be below the allowed ROE, but not more than 50 basis points below, in order to ensure a rate increase back to the allowed ROE.

and it would provide the means to improve and maintain a safe, adequate, and reliable distribution system. The ICR Rider would expand the scope of the MRP Rider to include (1) street and highway projects of government entities, and (2) legislative and administrative requirements relating to public health, safety, and environment. Mr. Harder asserts that the scope of the MRP Rider should be expanded to include street and highway improvements because a sizeable portion of what Arkla expends is not reimbursed. Also, the ICR Rider would avoid the need for the Company to file under Ark. Code Ann. 23-4-501 (Act 310) for the recovery of qualifying costs. (T. 32-36)

Staff Witness Booth testified that Arkla has not justified the need for the ICR Rider. Mr. Booth stated that Arkla is requesting that the Commission approve an open ended rider that goes far beyond the current MRP Rider in the types of costs that could be recovered. Mr. Booth argues that eligible facility relocation and city public work project costs could be recovered using an Act 310 or general rate case filing. (T. 1744-1746)

The AG, and AGC also oppose the Company's proposed ICR Rider. AG witness Marcus characterizes the ICR Rider as an open-ended program that should be summarily rejected. (T. 1353) AGC witness John contends that the ICR Rider will: (1) ensure that Arkla is made whole for certain expenses without providing any identifiable benefits to customers, and (2) insulate Arkla from the risk of doing business and ignore the fact that a company's business risk is factored into the determination of its return allowance. (T. 1091-1092)

Arkla Witness Harder asserted that the Commission should exercise its discretion to approve both Riders ICR and LCA. He contends that the ICR Rider provides a cost-effective alternative to the current MRP Rider by including other costs incurred as a result of government action. Mr. Harder argues that the ICR Rider reduces the cost of regulation by avoiding costs associated with Act 310 filings and the disputes that can occur under Act 310 filings. Mr. Harder believes that Ark. Code Ann. 23-4-108 does not specify the criteria to be followed nor does it limit the Commission's evaluation to Staff's automatic adjustment criteria. (T. 195-197)

In surrebuttal testimony, Staff Witness Booth testified that the Staff does not agree that the proposed ICR Rider is a cost-effective alternative to filing rate cases because: (1) the rider will generate additional revenue for Arkla with little regulatory oversight; and (2) it is unlikely the rider will result in lower bills or provide benefits to ratepayers. Mr. Booth further testified that, if the rider is approved, ratepayers can expect that, in contrast to the MRP Rider: (1) the ICR Rider will not limit the types of cost that it can recover; and (2) Arkla will recover a much larger annual revenue requirement under the proposed ICR Rider. (1778-1779) AG witness Marcus continues to recommend rejection of Arkla's proposed ICR Rider. Mr. Marcus contended that Arkla would have no incentive to be cost-conscious if recovery of costs were automatic, with a blank check and no regulatory review. With regard to highway relocations, the AG states that these costs have been ongoing for decades and are not new unusual requirements meriting a new policy. (T. 1451-1452) In sur-surrebuttal testimony, Arkla Witness Harder proposed modifications to the MRP Rider that would make it the vehicle for recovering cathodic protection expenses and costs that have been pre-approved for recovery. Mr. Harder, therefore, proposed that its MRP Rider should be designated as the ICR Rider because it will ultimately recover infrastructure costs beyond the scope of the bare steel and cast iron replacement program. (T. 244-245)

The Staff, AG, and AGC all recommend that the Commission reject Arkla's proposed ICR Rider. The Commission agrees with these parties' recommendation. Arkla already has in place the MRP Rider for the purpose of addressing safety concerns related to the replacement of bare steel and cast iron mains and services. The testimony of Staff witness Booth establishes that other regulatory mechanisms exist for Arkla to recover the eligible costs associated with relocating facilities for state, county, and city public works projects. Act 310 provides a means for Arkla to recover some of the costs that would be included in the ICR Rider. While Arkla could use the Act 310 filing procedure, Booth's testimony has shown that Arkla has not chosen, in approximately 14 years, to use an Act 310 filing to recover the cost of relocating pipeline facilities. Arkla could also use a general rate case filing to pursue the recovery of these costs. The Commission also finds that the proposed ICR Rider, as analyzed by Staff, does not meet the criteria applicable to the evaluation of other automatic adjustment clauses. Unlike, for example, the single expense for the purchase of natural gas, the ICR Rider would bundle together various types of capital costs and other expenses as a group. Also, unlike purchased gas costs, ICR-type costs could not typically be considered as volatile. Morevoer, Arkla has not shown that ICR-type costs that would be included for recovery are beyond Arkla's control as are natural gas costs.

In summary, Arkla has not fully utilized the regulatory options available to the Company. The proposed rider fails to meet the criteria traditionally used to evaluate automatic adjustment clauses. Arkla's proposed ICR Rider fails to balance both Company and ratepayer interests. While the proposed rider would keep Arkla whole and insulated from certain business risks, it would not provide the same level of benefits for ratepayers. For the reasons enumerated above, Arkla's late request to have the MRP Rider designated as the ICR Rider in recognition of its expanded scope for infrastructure costs is also denied.

Load Change Adjustment Rider

Arkla witness Cummings proposed a Load Change Adjustment Rider designed to reflect changes in two factors: (1) Number of customers; and (2) Usage per customer for Residential and Small Commercial Sales customers. (T. 822-836) In Rebuttal Testimony, Arkla witness Cummings dropped the component of the LCA that addressed changes in the number of customers. (T. 841-842)

According to Arkla witness Cummings, the Company has experienced a long-term declining trend in usage per customer in the Residential and Small Commercial Classes. (T. 828-832, 780-781) Also, according to Arkla witness Henry, Arkla's billing determinants have fallen from 31.5 BCF to 24.0 BCF since 1993. (T. 251-252) While other natural gas utilities have faced declines in usage per customer, they continue to experience growth in number of customers. (T. 243, 253) In contrast, Arkansas electric utilities have seen growth in electric residential customers and usage per customer. (T. 244, 253)

The proposed LCA Rider would adjust the bills of Residential and SCS customers for changes in non-gas revenue resulting from the changes in usage per customer levels used to set volumetric rates and the weather adjusted actual usage per customer levels experienced in the months following the implementation of those rates. According to Arkla witness Harder, two factors have affected the Company's ability to recover its cost of service: revenue-related risk and regulatory lag. (T. 30-31) Arkla witness Cummings alleged that the LCA rider: (1) should enable the Company to file rate cases less frequently, thus saving rate case expense, and (2) will more closely align the Company and customer interests of conserving and efficiently using gas ("decoupling"). (T. 33-35)

Staff witness Wright noted several problems with the LCA Rider. First, it would shift risk from Arkla's stockholders to Arkla's customers (T. 1901) This does not provide an equitable balance between the interests of the Company and its customers. (T. 1908) Second, the LCA Rider, if approved, would represent a significant departure from the traditional and fundamental ratemaking policies and procedures of this Commission. (T. 1905) Third, there is no guarantee that Arkla will file rate cases less frequently and that the associated savings, if any, will be passed on to customers. (T. 1906) Fourth, the LCA Rider is a type of "piecemeal" ratemaking where the level of the rate change would be based solely on the change in usage per customer without any review or determination of other factors such as rate base, expenses, or capital costs.

In response to the Company's concerns about "regulatory lag", Staff witness Booth claimed that Arkla has not fully availed itself of the provisions of Ark. Code Ann. §23-4-406 with regard to test-year and forward- looking cost data. (T. 1739-1740) Booth also noted that the LCA Rider fails the three criteria applicable for evaluation of an automatic adjustment clause: (1) the cost is a significant portion of a utility's operating costs; (2) the cost item exhibits extreme volatility and unpredictability, with that volatility defined as upward or downward-trending; and (3) the cost item is outside the control of the utility's management. (T. 1740-1742, 1772)

CEUG witness Ward opposed the LCA Rider because it: (1) provides the Company a mechanism to adjust rates without representation of intervening parties; (2) does not provide the Company incentive to promote growth in its service territory; and (3) guarantees a rate of return independent of performance. (T. 1158-1159)

AG witness Marcus would consider a tradeoff that accepts the Company's revised LCA Rider in exchange for no increases to customer charges and a reduction in the return on common equity that is commensurate with the risk reduction. (T. 1351) Further, if the proposed LCA Rider is approved, Mr. Marcus recommends that it should be combined with the existing Weather Normalization Adjustment clause into one adjustment clause to avoid unnecessary complexity. (T. 1352) Arkla rejects Mr. Marcus' recommendation that customer charges remain at their current levels and that the allowed return on equity be reduced if the LCA Rider is approved. (T. 41-45, 331, 856-857, 927-933) Arkla witness Cummings opposes the merging of the LCA and the WNA because customers would lose the immediate bill adjustments of the WNA if it were eliminated and incorporated into the LCA. (T. 835-836, 324)

AGC witness Johns opposed the LCA Rider because it would shift risk to customers and would lessen Arkla's incentive to maintain service levels used to set rates. (T. 1094) Additionally, Mr. John noted that the LCA rider is "piecemeal ratemaking" and that all interclass subsidies should be eliminated before adopting proposals which would extend the time between rate cases. (T. 1095-1096)

In Rebuttal Testimony, Mr. Cummings proposed the addition of Company funding of conservation and energy efficiency programs of 10% of LCA collections, up to $100,000 per year. These programs would include energy efficiency premises audits, educational programs, and load research programs. (T. 842) Also in Rebuttal Testimony, Arkla witness Henry alleged that the Company has incurred a $4.9 million marginal revenue erosion since its last rate case. (T. 328)

In Surrebuttal Testimony, Staff witness Wright noted that the 10% or $100,000 provision alone will be unlikely to produce significant benefits for customers (T. 1916). Further, Ms. Wright claimed that Arkla's expenses, as reported in its Annual Report to the Commission, have declined by approximately $8.2 million from 2002 to 2004, and that Staff's case here shows a revenue excess of $12.7 million. This indicates to Ms. Wright that Arkla's cost of service has declined by a greater amount than the estimated revenue loss from a decline in billing determinants. (T. 1918-1919, 1057) Arkla witness Henry responds that the $8.2 million corresponds to a change in capitalization policy in FERC Accounts 887 and 892, and that further declines were unlikely. (T. 351-352) CEUG witness Staley noted that the Company has increased its non-gas revenue requirement by 21% to 33% in a three to four year period, which is sufficient evidence to show that the Company has not attempted to aggressively control costs. (T. 1297-1298)

This Commission rejects the LCA Rider for the following reasons. First and foremost, the Company already has a number of automatic adjustment clauses, namely a GSR, WNA, and an MRP. The addition of another automatic adjustment clause would diminish the ability for enhanced scrutiny associated with traditional rate cases and also diminish the incentives for the Company to minimize costs. Second, the LCA Rider would inappropriately shift risk from Arkla's stockholders to Arkla's customers and, thus, would not provide an equitable balance between the interests of the Company and its customers. Third, the LCA Rider would be a type of "piecemeal" ratemaking where the level of the rate change would be based solely on the change in usage per customer without any review or determination of other potential offsetting factors such as rate base, expenses, or capital costs. Fourth, it would not provide the Company sufficient incentive to promote growth in its service territory. Fifth, the LCA Rider does not meet each of the three automatic adjustment clause criteria, outlined in the Prepared Testimony of Staff witness Booth.

VIII. VOLUNTARY FIXED PRICE OPTION

Arkla is requesting Commission approval of a Voluntary Fixed Price Option ("VFPO") Rider for residential and smaller SCS customers. The VFPO Rider provides these customers the option to have the GSR component of their utility bill fixed for a one-year period. (T. 271-272) Under Arkla's current GSR Rider, the Company is required to make two scheduled GSR filings annually: (1) a Scheduled Winter Season GSR filing effective for the billing months of November through March; and (2) a Scheduled Summer Season GSR filing effective for the billing months of April through October. Each filing is based on projected purchased gas costs and sales volumes, and includes a "true-up" of projected and actual gas costs incurred during the prior season. (T. 1748-1749) Under the VFPO, there would be no subsequent true-up of projected and actual costs. (T. 310)

In his prepared testimony, Staff witness Robert Booth recommended that the Commission reject the VFPO. Mr. Booth claimed there is no evidence that ratepayers will materially benefit under the VFPO. Mr. Booth claimed that the seasonal GSR rate filings have resulted in a stabilized GSR rate and, therefore, the VFPO Rider is not necessary to achieve the goal of a "fixed" GSR rate. (T. 1749) Mr. Booth also raised concerns with respect to the Company's ability to administer the VFPO, given the Company's prior purchased gas cost accounting errors. (T. 1750) In his surrebuttal testimony, Mr. Booth raised an additional concern that the VFPO will add complexity to the GSR process. (T. 1782)

CEUG witness Staley recommended that the VFPO be provided only to residential customers and requested it be denied for SCS customers. He recommended that all SCS customers be provided the opportunity to transport gas to attain the benefits of a fixed price. (T. 1215)

In his rebuttal testimony and again in his Sur-Surrebuttal testimony, Arkla witness Henry claimed the VFPO boils down to a policy issue that can only be answered by the Commission. Mr. Henry encouraged the Commission to approve the VFPO. (T. 3132, 346) With respect to CEUG witness Staley's recommendation, Mr. Henry claimed that transportation service is simply not economic for many SCS customers and, therefore, they should not be denied the VFPO option. (T. 312)

The Commission finds merit in the concerns expressed by Staff. In the Commission's *Natural Gas Procurement Plan Rules*, Section 6, Customer Education, it states that "each gas utility shall engage in appropriate customer education efforts concerning the availability and benefits of levelized billing or average payment plans" ("Plans"). Generally, these Plans allow customers to even out their monthly bills by paying more for their bill in the summer and less than the full amount in the winter. Such Plans can help minimize and stabilize customer bills during the winter heating season. Under Arkla's tariffs, customers may avail themselves of these Plans. These Plans, in addition to the seasonal GSR, also produce virtually the same "fixed price" result with less cost, complexity, or potential for cross-subsidies.

Since the seasonal GSR rate filings have resulted in a stabilized GSR rate, and the combination of the new GSR system with levelized payment plan options produces an essentially "fixed bill," there is no reason to approve a VFPO that adds complexity to the GSR process and can cause more billing accounting problems. The Commission is also concerned with the potential for cross-subsidization and cost shifting to customers who do not elect the VFPO. Cost shifting could occur if the actual gas costs of VFPO customers exceed gas cost recoveries. Therefore, we reject the VFPO Rider.

IX. RURAL EXTENSION FUND ("FUND")

According to testimony in this proceeding, the Fund was approved in Docket No. 85-043-U for the purpose of using post-1970 investment tax credits to fund the extension of gas mains into areas where such service would otherwise not have been practical. Interest on the funds was set in Docket No. 93-081-U at the Commission approved customer deposit rate. Arkla has proposed to terminate the fund because the Company has not had a sufficient number of economically feasible, rural extension projects to which the Fund could be applied. Arkla proposes that the Fund be terminated and distributed in equal shares to the Good Neighbor Fund ("GNF") and the Weatherization Assistance Program ("WAP"). The GNF is designed to help Arkla customers who have trouble paying their gas bill during the winter heating season, and who need financial assistance to maintain their gas service. The WAP installs energy conservation materials and appliances in homes of low-income families annually to lower their utility bills. (T. 25, 29, 197, 1754)

Staff Witness Booth testified that the approximate balance of the Fund is $1,300,408 as of April 30, 2005. Mr. Booth agrees with the Company that the Fund should be terminated. However, Mr. Booth does not agree with Arkla's proposal to distribute the Fund in equal shares to the GNF and the WAP. Mr. Booth recommends that: (1) the Fund monies be returned to all customers; (2) Arkla credit the accumulated balance of the fund to Arkla's MRP Rider; and (3) Arkla clearly document the crediting of the Fund amount in the MRP filings, in accordance with Section 2.3.4 of Staff's proposed MRP Rider. (T. 1755-1756, 1786-1787)

Both Arkla and the Staff agree that the fund should be terminated and that the monies remaining in the fund distributed to other various recipients. We agree. The only remaining issue is who should receive the balance of the monies in the Fund. Arkla's proposal to distribute the funds to the GNF and the WAP, while laudable, would target fewer customers than Staff's recommendation. Staff's proposal is adopted since it will ensure that all customers will receive some benefit from the balance of the fund.

X. OTHER TARIFF ISSUES

GSR – Language

The Company has proposed that the following tariff language be added to the text of the GSR Rider:

> "The Company shall recover all of its gas costs from its customers under this rider and the Voluntary Fixed Price Option ("VFPO"), Rider Schedule No. 6" (Schedule I, page 132).

Staff witness Booth disagreed with the proposed language, claiming that the text appears to be inserting a requirement that Arkla be guaranteed recovery of its gas costs. Mr. Booth further claimed that the Company has not supported the proposed language. (T. 1754) Arkla witness Henry claimed that the proposed tariff language was simply intended to recognize that some of the Company's gas costs would now be recovered through the proposed VFPO. Previously, all gas costs were recovered through the GSR. (T. 320)

In his surrebuttal testimony, Staff witness Booth continued to recommend that the proposed language be rejected. The basis of his recommendation was that he continued to recommend that the VFPO Rider be rejected. (T. 1785)

As discussed above, the Commission has rejected the proposed VFPO Rider. Therefore the proposed GSR language is also rejected.

Master Metering/Combined Billing

CEUG witness Staley testified that the Stipulation and Settlement Agreement in Arkla's last rate case in Docket No. 01-243-U directed the parties to negotiate in good faith to develop master metering/combined billing ("MMCB") guidelines for Arkla. While the parties to Arkla's previous rate case met to develop the guidelines, they were unable to reach agreement on a set of guidelines. In this proceeding, CEUG witness Staley recommended approval of the MMCP guidelines attached to his direct testimony. (T. 1196) Arkla witness Bish testified that this rate proceeding is not the appropriate proceeding to adopt MMCB guidelines. Mr. Bish contended that the APSC General Service Rule 5.20 ("Rule") does not permit combined billing in the manner advocated by CEUG. He recommended that a separate proceeding involving all of the other gas utilities as parties would be a more appropriate forum to address this issue. (T. 449) In surrebuttal testimony, CEUG witness Staley argued that Mr. Bish did not raise any specific objections to CEUG's guidelines. Mr. Staley asserted that Mr. Bish's general concerns are without merit. (T. 1263-1267) Staff witness Booth agreed with Arkla that a rate case docket is not the appropriate proceeding to consider this issue because MMCB is governed by the Commission's Rule. Mr. Booth recommended that any changes to the Rule should be adopted by the Commission in a generic proceeding or a rule-making docket to ensure that all interested/affected parties can participate. (T. 1788) In sur-surrebuttal testimony, Arkla witness Bish continued to recommend that the Commission not adopt MMCB guidelines in this proceeding. He contended that addressing the issue for each utility in separate rate cases in a piecemeal fashion is not conducive to either participation by all affected parties or a consistent result. (Bish SS2-5)

For the reasons advanced by Arkla and the Staff, the Commission finds that any changes to the MMCB Rule should be addressed in a generic rule-making proceeding and not in this docket. The Commission also notes that the guidelines stemming from Docket No. 01-243-U, were developed by the parties between that docket and this proceeding. Therefore, we do not find CEUG's contention that the guidelines must be developed within the confines of a rate case to be persuasive. Therefore, the Commission finds that any interested party (or parties) may petition the Commission to open such a proceeding to address issues related to MMCB. In the alternative, the parties (and any other interested parties) may continue to work on their own to finalize the proposed guidelines contemplated in Docket No. 01-243-U.

Upstream Contract Flexibility

CEUG witness Ward recommended a modification of the Company's capacity release policy to provide greater flexibility for Transportation Service Option ("TSO") customers. Arkla's current policy is to specify the amount of pipeline capacity to be released to the TSO customer. If the TSO customer does not accept the capacity release, Arkla assesses the customer with the fixed charges associated with any resulting excess capacity. Mr. Ward noted that this policy was implemented because of Arkla's belief that TSO customers were burdening the remaining Supply Service Option ("SSO") customers with excess capacity due to differences between the capacity releases elected by TSO customers and their allocated contract capacity. While agreeing that SSO customers should be kept economically whole and not burdened with excess capacity, Mr. Ward proposes that Arkla should put in place contractual mechanisms with its upstream pipeline that provide TSO customers with the level of choice intended for those customers. (T. 1162-1164)

In Rebuttal Testimony, Arkla witness TheBerge agreed that Mr. Ward accurately characterized the problem. However, he contended that the solution proposed by Mr. Ward to balance the interests of TSO and SSO customers cannot be implemented without additional costs. That is, increasing the flexibility of the contract with Arkla's upstream supplier to accommodate adjustments for TSO customers would increase the costs of that upstream contract, making it more expensive for all customers. (T. 639)

In his Surrebuttal Testimony, Mr. Ward argued that Mr. TheBerge provided no support for his claim that upstream contract flexibility would result in higher costs. He stated that: "In a truly competitive environment, this additional flexibility may result in no additional cost to the Company's customers." (T. 1185) Mr. TheBerge responded that this conclusion is totally at odds with Arkla's experience that additional flexibility translates into higher costs. (T. 723)

We decline to order the Company to modify its capacity release policy as proposed by Mr. Ward. We agree that experience has shown that increasing the level of contact flexibility to allow reductions in capacity will almost certainly result in increased upstream pipeline capacity costs.

XI. RETURN ON EQUITY ADJUSTMENT

Staff witness Booth recommends that Arkla's return on equity be set at the lower end of the range of reasonable equity returns. Various Staff witnesses identified several concerns with Arkla's: (1) filing of its Application; (2) administration of its tariffs; (3) accounting for retirements of plant; (4) costs allocated by its accounting system; and (5) retention of data required for the depreciation study. Staff witness Booth contended that the above concerns cast serious doubt on Arkla's ability to provide adequate service to its customers. Mr. Booth argued that, when a public utility does not provide a satisfactory level of compliance with the

Commission's Rules and does not provide a satisfactory level of customer service, it is appropriate to adjust its return on equity. (T. 1761-62, 1764)

Staff witness Fritchman testified that Arkla filed three revisions to its deficient original Application filed on November 24, 2004 in an attempt to correct these deficiencies. Ms. Fritchman asserted that as a result, Staff spent considerable time reviewing the original Application and then reviewing and analyzing all the revisions. She claims that Arkla's filing of a deficient Application interrupted and frustrated Staff's review and analysis of Arkla's requested rate relief. (T.1517-1791) Ms. Fritchman further testified that, as a result of a her audit of Arkla's Temporary Low Income Gas Recovery Program ("TLICGRP"), she determined that Arkla was unaware that it had failed to credit $2,364,599 back to ratepayers as required by the Commission in Docket No. 01-248-U. Also, Arkla did not have in place a process to properly track collections under the TLICGRP. (T. 1510-1513) Ms. Fritchman found that Arkla did not exercise adequate oversight to ensure compliance with its MRP Rider. As a result, over-collections totaling $294,879 occurred because Arkla did not have adequate controls in place to ensure that costs that did not meet the criteria were not included for recovery. (T. 1513-1516) Regarding Arkla's Weather Normalization Adjustment Rider ("WNA"), Fritchman alleged that Arkla, in November 2004, failed to apply the WNA to the bills of its residential and small sales customers. Additionally, Arkla did not compute the sales tax applicable to the WNA charge. (T. 1516-1517) Ms. Fritchman also determined that Arkla had trouble in identifying direct charged and allocated costs in a timely and accurate manner. She identified several instances where costs were improperly charged to Arkla by affiliates and by Arkla Corporate. (T. 1521-1524)

Staff witness Williams testified that Arkla still had assets on its books that were no longer used and useful, assets that Arkla no longer owned, accounts in which the Company failed to book retirements, and assets that were fully amortized. (T. 1928-1932) Staff witness Freier discovered that Arkla had not been using the correct depreciation rates that were approved in Docket No. 01-243-U. Ms. Freier concluded that Arkla needs considerable improvement in its data retention and record keeping processes. (T. 2016-2022)

Various Arkla witnesses responded to the Staff's concerns with Arkla's tariff administration, application, and accounting. Arkla witness Harder, in citing a Continental Telephone Company of Arkansas case, acknowledges that there is precedent for reducing a Company's ROE for failure to provide adequate customer service. (T. 175) However, Mr. Harder argued that case concerned the actual quality of the utility service provided to customers, not the type of concerns identified by Staff in this case. He asserted that the Staff's concerns in this docket have no direct bearing on customer service. (T. 175-177) Mr. Harder responded to Staff's concerns that Arkla failed to properly administer its TLICGRP by stating that: (1) this was a one-time program that did not conform with any existing accounting or billing mechanism; (2) when Arkla became aware of problems; it developed corrective measures; and (3) the amount of the over-billing errors represented only a small portion of the total amount billed. (T. 179-180)

Regarding Staff's concerns about the MRP Rider, Mr. Harder observed that with any program of this magnitude, mistakes will occur. He also noted that the MRP under billing error represents only a small portion of the total billings during that time period and thus should not warrant a reduction in the Company's ROE. (T. 180-181) Concerning Arkla's WNA, Mr. Harder stated that the Company remedied this error in accordance with Commission Rules. Mr. Harder insisted that the failure to bill sales tax on the WNA was not an error, but rather a conscious decision to forego the collection of sales tax from its customers. (T. 181-183) With regard to deficiencies in the Company's Application, Mr. Harder stated that the alleged deficiencies did not materially affect the amount sought by the Company or Staff's audit. Mr. Harder testified that Arkla subsequently reduced its requested rate relief as a result of a filing deficiency. Mr. Harder also asserted that Arkla has not experienced problems with the filing requirements in other jurisdictions. (T. 174-186)

Arkla witness Hamilton contended that the Staff should modify its auditing procedures to obtain the information that it needs by examining the accounting records that are maintained by the Arkla corporate offices and developing an audit program tailored to the specific requirements of each of the larger companies it audits. With regard to the Staff's recommendation that it have access to external auditor working papers, Mr. Hamiliton does not believe that future external auditor engagement letters should provide the Staff with full access to all working papers created by the Company's external auditor. He contended that audit working papers are not designed in a manner that would or should permit third parties to use the information found in those audit working papers for other purposes. (T. 1038-1047)

Arkla witness Fitzgerald's testimony addressed certain of the allegations made by the Staff concerning various deficiencies in the Company's accounting system and practices. Mr. Fitzgerald argued that, even if each of the accounting allegations were true, the Staff has not presented any evidence that the deficiencies have negatively affected the quality of service provided by the Company. Mr. Fitzgerald further testified that the Staff has not cited any specific rules that Arkla violated in reaching its conclusion that Arkla's accounting and system and reporting processes are out of compliance with Commission Rules or are not suitable for regulatory purposes. (T. 1951-1953)

In surrebuttal testimony, Staff witness Fritchman continued to assert that the Company failed to properly administer and monitor the operation of the TLICGRP and MRP Riders. Ms. Fritchman contended that Arkla's lack of administrative oversight of these riders raises the concern that similar problems, if not addressed, could occur with the operation of other tariffs. (T. 1567) She stated that the magnitude of the errors in administering the TLICGRP and MRP Rider cannot be dismissed as being immaterial. (T. 1567-1570) The Staff continues to assert that the problems with Arkla's Application impeded its review and audit. (T. 1572-1573) Regarding access to external auditor work papers, Ms. Fritchman pointed out that Staff routinely reviews the external auditor work papers for the companies it audits to determine if there are any issues that should be further investigated. (T. 1574-1575) Staff witness Booth testified that Arkla continues to fail in its obligation as a regulated public utility. Mr. Booth asserted that, while the facts in this case differ from the Continental case, the Continental case recognized that the cost of equity can be adjusted when supported by certain facts. He argued that, if a utility fails to follow any standard, regulation, or practice set by the Commission, the utility has failed to meet its obligations as a regulated public utility and has thus negatively affected its customers. (T. 1789-1791)

In sur-surrebuttal testimony, Arkla witness Harder testified that the Staff has not shown that its downward ROE adjustment is permitted under Arkansas law, does not violate Arkla's right to due process, and is proportionate to the alleged harm to ratepayers. (T. 237) Regarding the administration of its tariffs, Mr. Harder stated that Arkla takes billing problems seriously and that it seeks to promptly correct such problems and take corrective action to prevent their recurrence. Mr. Harder argued that Staff's audit was not impaired despite the problems the Staff experienced with Arkla's Application. According to Harder, this was evidenced by the fact that the Staff was able to comply with all of the established procedural dates in this proceeding.

Arkla witness Hamilton continued to assert that gaining access to the external audit working papers provides little, if any, additional rate case audit support and that if access is granted, the cost of the audit will increase. (T. 1051-1052) Arkla witness Fitzgerald testified that except for certain MFRs, the Staff did not cite one Commission rule that Arkla violated. Mr. Fitzgerald contended that there were only three accounting-related errors cited by Staff, which represents only a small portion of an enormous number of accounting entries made daily by the Company. He contended that Arkla acted properly and reasonably by correcting each of the accounting errors, and Arkla agreed to institute various new processes to help minimize their chances of recurring in the future. (T. 985-987) Mr. Fitzgerald further testified that, without a showing of persistently inadequate customer service, the Commission has no history of punishing a utility through its rate of return and has held that a punitive ROE is contrary to accepted legal standards for reasonable returns. (T. 987)

The primary issue here is whether or not Arkla's administration of its tariffs, its accounting and recordkeeping practices, and its supporting documentation for rate applications have been deficient to the extent that it would warrant the selection of an ROE at some point below the middle of Staff's recommended range of reasonableness. At the hearing, Staff witness Booth testified that "any point within the range of reasonable returns is a reasonable return, and there does not need to be even a reason for the Commission to choose any point within that range since any point is a reasonable range." (T. 955, 965-966) The Commission finds that the balance of Staff's and Arkla's testimony on this issue reflects the need to adopt an ROE between Staff's recommendation and the normally-accepted ROE midpoint.

Testimony has been presented by Staff witnesses which identified numerous instances in which Arkla's billing of customers, accounting practices, and rate case filings were deficient. While Arkla asserts that the alleged deficiencies had no bearing on the quality of service provided to its customers, quality of service has as much to do with utilizing proper inventory and accounting practices as it does pipe replacement and quality field service. Arkla, as a public utility, is required and obligated to maintain proper accounting and financial records in compliance with uniform accounting practices, and to file Applications for rate changes in compliance with the Commission's Minimum Filing Requirements ("MFRs"). In return for compliance with these accounting requirements, among others, utilities are allowed to recover their reasonable and prudently-incurred expenses, earn a fair and reasonable return on capital investments, and enjoy a monopoly service territory. A public utility's accounting systems form the basis for establishing appropriate rates for its customers. For ratemaking purposes, it is the regulatory commission which has the responsibility and authority for exercising control of the rates, charges and services provided by the utility company. The Commission notes that Arkla did not substantively deny the allegations made by Staff regarding the administration of its TLICGRP, MRP Rider, or WNA, or that there were various deficiencies with its Application filing package. Arkla simply provided various explanations such as: (1) the overbilling errors were small in comparison with the total amount billed; (2) humans do make mistakes; (3) the billing errors were corrected; and (4) the Application deficiencies did not materially affect the amount of revenue sought by the Company or impair Staff's investigation.

The Commission cannot ignore what appears to be a pattern of deficiencies as to Arkla's recordkeeping, accounting systems, customer billings, and rate case filings. Staff witness Booth testified that Arkla's rate Applications in its last four rate cases were also cited for numerous MFR deficiencies. These deficiencies occurred even after Arkla was given waivers of certain MFRs in those cases. While it appears that Arkla did address some of the Staff's accounting concerns identified in Arkla's last rate case (Docket No. 01-243-U), the reoccurrence of related and numerous problems in this docket and in recent Staff tariff audits leads the Commission to believe that the Company has not yet undertaken the serious corrective actions it must take in order to establish a prudent and credible basis for its accounting and billing systems --- all of which are fundamental to the determination of reasonable rates. Accordingly, an ROE below the mid-point of the range that reflects poor performance in this area will hopefully serve as an appropriate inducement to incent corrective action by Arkla that will produce more confidence and integrity in future inventory numbers, cost accounting, customer billing, rate case applications, and compliance with the Commission's MFRs.

In describing the difference between the Continental Telephone Case and this proceeding, the Company argued that: (1) in this proceeding, there is no evidence that the quality of service was inadequate; (2) the evidence in this case does not show a pattern of non-compliance; and (3) absent a showing of poor customer service, the Commission has no history of punishing a utility through its rate of return. (T. 1566) The Commission does not agree with Arkla's reasoning. Arkla's service to its customers is provided via its rate schedules, riders, and tariffs. If the quality of customer service is inadequate in the administration of these tariffs, riders, and rate schedules, or the accounting and inventory practices that underline those rate schedules, the Commission may apply the "Continental case standard." The record in this proceeding provides substantial evidence to support a finding that the quality of service provided by Arkla by its administration of several Arkla riders was inadequate. Through its audits, the Staff found that ratepayers were overcharged by approximately $2,659,478 for the service that Arkla provided through its TLICGRP and MRP Riders. (T. 1566-1567) Also, the Staff found that Arkla misapplied the terms of its WNA Rider to bills of its residential and small commercial customers in November 2001. (T. 1566-1567)

The record also shows a pattern of non-compliance with Commission rules and regulations. As previously mentioned, uncontroverted testimony was presented that Arkla's Applications in its most recent Arkansas rate cases in Docket Nos. 01-243-U, 94-175-U, 93-081-U, and 92-032-U were cited for numerous MFR deficiencies even after being granted waivers of certain MFRs. Furthermore, the deficiencies occurred again in the current Application. (T. 1792) The record also shows that: (1) Arkla's accounting system failed to properly account for retirements of plant no longer serving customers, and failed to readily identify the amounts and types of cost being allocated to it; and (2) Arkla failed to retain data required for depreciation studies and record keeping processes. (T. 1790) When taken as a whole, this evidence establishes a pattern of persistent and inadequate customer service and non-compliance with standard accounting practices and Commission rules and regulations. The fact that the Commission may not have a consistent history of reducing a rate of return allowance for service quality and rule violation issues only indicates that the magnitude of such patterns of conduct as reflected in this case have not often occurred in this state.

The Commission, however, is encouraged by the testimony of Arkla Vice President and Controller, Walter L. Fitzgerald. Mr. Fitzgerald testified that the Company has made improvements in various accounting and computing systems. Some of the improvements the Company identified included: (1) a process called "record and report" which tracks transactions through the accounting process; (2) a computer system which tracks various processes, and (3) since the last rate case, a "special projects ledger.[12] (T. 886-887) Mr. Fitzgerald was confident that the problems that Staff has identified in the past, and in this proceeding, have been addressed and that the Company will continue to maintain these "state of the art" type systems. (T. 886-888) Given these improvements cited by Arkla and its commitment that the problems have been

[12] The Commission notes that Staff witnesses Fritchman and Booth indicated that, while Arkla has made changes to its accounting systems since Arkla's last rate case, some of the same problems from the last rate cases were identified in this proceeding. With regard to Arkla's Application deficiencies, the Staff indicated it would not know whether those type problems have been resolved until Arkla files its next rate Application. (T. 894, 923, 961-63)

and will continue to be addressed, the Commission will modify Staff's recommendation that Arkla's ROE be set at the lower end of Staff's range of reasonableness and set Arkla's ROE in this proceeding at 9.45%, which is approximately half-way between Staff's recommendation and the mid-point of the range of reasonableness.

The Commission, directs its General Staff, to closely monitor Arkla's progress in correcting the various cited deficiencies. If progress is not being made as promised by Arkla, the Commission will take appropriate steps to ensure that deficiencies are corrected in a timely manner. Prior to its next rate case, Arkla must bring its books and records into full compliance with standard accounting practices and with the Commission's MFRs.

XII. STAFF RECORDKEEPING AND REPORTING RECOMMENDATIONS

Staff witness Booth identified seven Staff recordkeeping and reporting recommendations that Arkla either partially accepted or completely rejected.[13] Mr. Booth argued that Arkla should be required to comply with the recommendations that the Company did not fully accept and those that Arkla rejected outright. (T. 1779-1780, 1798-1804) The Staff recommendations relate to the following issues: (1) external audit work papers, (2) retirement inventory, (3) annual depreciation study data, (4) pre-tax rate for MRP over-collections, (5) allocation of affiliate charges, (6) allocation of meters, regulator, etc., and (7) APSC-approved depreciation rates.

Access to External Audit Workpapers

In her direct testimony, Staff witness Fritchman discussed the difficulties in gaining access to the workpapers prepared by CenterPoint's external auditor due to confidentiality issues.

[13] The Commission's finding on Recommendations Nos. 2,3, and 7 have been incorporated into the order's section on depreciation rates/expense.

Accordingly, she recommended that the Commission require that all future engagement letters between CenterPoint Energy and its external auditor expressly require that full access to all workpapers created by the external auditor be provided to the Staff of the APSC. (T. 1521)

In response, Arkla presented the Rebuttal testimony of Mr. Fitzgerald and Mr. Hamilton. Mr. Fitzgerald explained that the difficulties were not caused by the Company and that it does not have control over the workpapers prepared by its external auditor (currently Deloitte and Touche, LLP). He also noted that the issues with Deloitte & Touche had been resolved. (T. 958-959) Mr. Hamilton testified that the workpapers of the outside auditor were not prepared for the purpose of the ratemaking process and should not be relied upon for that purpose. He also testified that Ms. Fritchman's recommendation would increase the costs of the audit to the Company while providing little meaningful information to the Staff. (T. 1044-1045) In response to Arkla's rebuttal, Ms. Fritchman continued to recommend that access to the external auditor's workpapers be required as a provision in all future engagement letters with external auditors. However, she modified her recommendation to make it clear that the external audit will not be conducted for the purposes of a third party and that the audit will not replace or supplant the procedures or inquiries that should be undertaken by the regulator for its purposes. Ms. Fritchman expressed the view that this should avoid the additional costs noted by Mr. Hamilton. (T. 1577-1578) In Sur-Surrebuttal, Mr. Fitzgerald noted that the Company will attempt to negotiate such terms with its external auditor. However, the Company has no ability to dictate the terms of an engagement letter with external independent auditors.

We recognize that Arkla does not have the ability to dictate the terms of an engagement letter with outside independent auditors. Accordingly, we will not order the Company to include a provision in all future engagement letters which requires the external audit workpapers to be provided to the Staff. We do, however, direct the Company to make it clear to its external auditors that its workpapers are to be made available for review under the terms of an appropriate confidentiality agreement.

Pre-Tax Rate on MRP Rider Over-collections

Staff witness Fritchman testified that the MRP Rider recovers on an interim basis between rate cases Arkla's cost of replacing bare steel and cast iron mains along with associated services. Ms. Fritchman further testified that as a result of her audit of the MRP Rider she discovered an Arkla over-collection of $294,879 which included interest computed pursuant to Rule 5.19 of the Commission's *General Service Rules.* In light of Arkla's over-recovery, Ms. Fritchman recommended that the interest rate applicable to any over-collections be set at the pre-tax rate of return determined in this proceeding. (T. 1513-1515) Arkla witness Harder argued that the Staff's recommendation is "one-sided" and is unwarranted and excessive. (T. 181) Staff witness Booth disagreed, stating that, since under the MRP Rider Arkla recovers the pre-tax return on qualifying investments, it is reasonable to use that rate of return to compensate ratepayers for any over-collections. (T. 1780-1781) Mr. Harder proposed that the use of the pre-tax rate of return for over-collections under the MRP Rider should be removed, or alternatively, the pre-tax return should apply to both over-collections and under-collections. (T. 239-244)

The Commission rejects Staff's recommendation to use the pre-tax rate of return for MRP Rider over-collections. Interest on MRP billing corrections, i.e., over or under-collections will be assessed pursuant to Rule 5.19 of the Commission's *General Service Rules.*

Allocation of Affiliate Charges

Staff identified several problems with obtaining accurate information on costs that were allocated and direct charged to Arkla from its affiliates. Affiliate costs allocated to Arkla lose their identity because thousands of transactions are aggregated at the end of the month prior to being allocated. (T. 1521-1522) This significantly increases the difficulty of tracing costs on Arkla's books back to source documents. Staff has not experienced problems of this magnitude with other multi-jurisdictional utilities that the Commission regulates. (T. 1795)

Two examples of these problems are charitable contributions costs (T. 1521, 1523) and Minnegasco costs. (T. 1521-1522) Other examples of costs improperly allocated to Arkansas that came out during the hearing are: (1) Texas lieutenant governor reception; (2) TicketMaster tickets; (3) Electric Power conference; and (4) Indiana University Varsity Shop. (T. 877-881) The Company failed to eliminate some charitable contribution costs from its revenue requirement as required by the MFR. Absent the intervention of Staff witness Fritchman, these costs would have been inappropriately recovered from Arkansas ratepayers. (T. 1582)

Staff recommends that the Commission require Arkla to develop a procedure whereby costs that are allocated or direct charged from affiliates can be specifically identified by Arkla so that the information will be provided in a clear, accurate, and timely manner for regulatory purposes. This procedure should be filed with the Commission by January 3, 2006. (T. 1524)

The Company dismissed these alleged difficulties as being insignificant, or caused by human error on the part of the Company, or data input error on the part of the Company, or the manner in which Staff conducted its audit. Nevertheless, the Company has indicated that it will file its procedure that identifies direct versus allocated costs with the Commission by January 3, 2006.

We hereby direct Arkla to file the procedure recommended by Staff with the Commission by January 3, 2006. Prior to the filing Arkla will consult with Staff, and other interested intervenors, regarding the details of such a procedure.

Allocation of Meters, Regulators, and Domestic Meter Installations

Staff recommends that the Company be required to directly assign the costs of domestic meters, domestic regulators, and domestic meter installations for use in the Arkansas jurisdiction to Arkansas. The Company proposed that going forward such direct assignments be made, but that the historical balance of these assets be allocated on the basis of customer count. Staff would like to see the results of that historical allocation before it can be assessed.

We agree with this approach and hereby direct Arkla to file with the Commission by January 3, 2006 all workpapers associated with the historical allocations, and a specific procedure for direct assignment going forward. Prior to the filing Arkla will consult with Staff, and other interested intervenors, regarding the details of such a procedure.

THEREFORE, the Commission orders as follows:

1. That the rates and tariffs proposed in this proceeding by Arkla are hereby disapproved.

2. Arkla is ordered to file new rates and tariffs designed in conformity with this order.[14]

3. Upon and review and approval by subsequent order, the new rates and tariffs shall become effective for meters read on or after September 25, 2005.

BY ORDER OF THE COMMISSION

This 19th day of September, 2005

Sandra L. Hochstetter

Sandra L. Hochstetter, Chairman

Daryl E. Bassett

Daryl E. Bassett, Commissioner

Randy Bynum, Commissioner

Diana K. Wilson

Diana K. Wilson
Secretary of the Commission

I hereby certify that the following order issued by the Arkansas Public Service Commission has been served on all parties of record this date by U.S. mail with postage prepaid, using the address of each party as indicated in the official docket file.

Diana K. Wilson

Diana K. Wilson
Secrectary of the Commission
Date 9/19/05

[14] Arkla's rates will be reduced by approximately $11.5 million.

FEDERAL RESERVE statistical release

H.15 (519) SELECTED INTEREST RATES
Yields in percent per annum

For use at 2:30 p.m. Eastern Time
September 19, 2005

Instruments	2005 Sep 12	2005 Sep 13	2005 Sep 14	2005 Sep 15	2005 Sep 16	Week Ending Sep 16	Week Ending Sep 9	2005 Aug
Federal funds (effective) [1 2 3]	3.50	3.45	3.54	3.67	3.62	3.49	3.51	3.50
Commercial paper [3 4 5]								
Nonfinancial								
1-month	3.59	3.54	3.62	3.63	3.69	3.61	3.55	3.47
2-month	3.62	3.63	3.62	3.65	3.68	3.64	3.60	3.53
3-month	n.a.	3.69	3.71	3.73	n.a.	3.71	3.64	3.64
Financial								
1-month	3.63	3.65	3.69	3.68	3.69	3.67	3.61	3.50
2-month	3.67	3.70	3.72	3.74	3.73	3.71	3.66	3.60
3-month	3.74	3.76	3.77	3.77	3.79	3.77	3.71	3.69
CDs (secondary market) [3 6]								
1-month	3.71	3.73	3.74	3.75	3.76	3.74	3.67	3.56
3-month	3.82	3.84	3.83	3.84	3.85	3.84	3.77	3.77
6-month	3.96	3.98	3.96	3.97	3.98	3.97	3.89	3.99
Eurodollar deposits (London) [3 7]								
1-month	3.68	3.70	3.71	3.74	3.74	3.71	3.65	3.54
3-month	3.80	3.81	3.81	3.83	3.83	3.82	3.75	3.74
6-month	3.93	3.95	3.94	3.94	3.95	3.94	3.88	3.96
Bank prime loan [2 3 8]	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.44
Discount window primary credit [2 9]	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.44
U.S. government securities								
Treasury bills (secondary market) [3 4]								
4-week	3.26	3.25	3.20	3.17	3.16	3.21	3.28	3.28
3-month	3.44	3.40	3.35	3.37	3.42	3.40	3.42	3.44
6-month	3.67	3.65	3.64	3.65	3.69	3.66	3.60	3.66
Treasury constant maturities								
Nominal [10]								
1-month	3.33	3.30	3.25	3.23	3.23	3.27	3.35	3.34
3-month	3.51	3.47	3.42	3.45	3.50	3.47	3.50	3.52
6-month	3.79	3.77	3.76	3.77	3.81	3.78	3.72	3.78
1-year	3.83	3.81	3.81	3.81	3.86	3.82	3.76	3.87
2-year	3.92	3.88	3.90	3.90	3.97	3.91	3.86	4.04
3-year	3.93	3.88	3.91	3.93	4.00	3.93	3.88	4.08
5-year	3.98	3.93	3.96	3.99	4.05	3.98	3.93	4.12
7-year	4.06	4.01	4.04	4.08	4.13	4.06	4.01	4.18
10-year	4.18	4.14	4.17	4.22	4.26	4.19	4.13	4.26
20-year [11]	4.50	4.47	4.50	4.56	4.61	4.53	4.44	4.53
Inflation indexed [12]								
5-year	1.37	1.34	1.36	1.37	1.40	1.37	1.38	1.71
7-year	1.56	1.53	1.54	1.56	1.58	1.55	1.55	1.79
10-year	1.69	1.67	1.68	1.71	1.73	1.70	1.67	1.89
20-year	1.94	1.91	1.92	1.96	1.97	1.94	1.93	2.02
Inflation-indexed long-term average [13]	1.90	1.87	1.88	1.92	1.93	1.90	1.89	1.98
Interest rate swaps [14]								
1-year	4.18	4.16	4.17	4.16	4.21	4.18	4.11	4.27
2-year	4.27	4.24	4.25	4.25	4.31	4.26	4.21	4.42
3-year	4.32	4.28	4.28	4.30	4.38	4.31	4.27	4.48
4-year	4.36	4.31	4.31	4.34	4.43	4.35	4.31	4.52
5-year	4.40	4.34	4.35	4.39	4.48	4.39	4.35	4.56
7-year	4.48	4.43	4.43	4.48	4.58	4.48	4.43	4.62
10-year	4.59	4.54	4.55	4.61	4.71	4.60	4.54	4.71
30-year	4.87	4.83	4.84	4.91	5.01	4.89	4.83	4.93
Corporate bonds								
Moody's seasoned								
Aaa [15]	5.10	5.07	5.10	5.16	5.22	5.13	5.05	5.09
Baa	6.00	5.97	6.00	6.06	6.11	6.03	5.96	5.96
State & local bonds [16]				4.30		4.30	4.26	4.32
Conventional mortgages [17]				5.74		5.74	5.71	5.82

See overleaf for footnotes
n.a.-- not available

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FOOTNOTES

1. The daily effective federal funds rate is a weighted average of rates on brokered trades.
2. Weekly figures are averages of 7 calendar days ending on Wednesday of the current week; monthly figures include each calendar day in the month.
3. Annualized using a 360-day year or bank interest.
4. On a discount basis.
5. Interest rates interpolated from data on certain commercial paper trades settled by The Depository Trust Company. The trades represent sales of commercial paper by dealers or direct issuers to investors (that is, the offer side). The 1-, 2-, and 3-month rates are equivalent to the 30-, 60-, and 90-day dates reported on the Board's Commercial Paper Web page (www.federalreserve.gov/releases/cp).
6. An average of dealer bid rates on nationally traded certificates of deposit.
7. Bid rates for Eurodollar deposits collected around 9:30 a.m. Eastern time.
8. Rate posted by a majority of top 25 (by assets in domestic offices) insured U.S.-chartered commercial banks. Prime is one of several base rates used by banks to price short-term business loans.
9. The rate charged for discounts made and advances extended under the Federal Reserve's primary credit discount window program, which became effective January 9, 2003. This rate replaces that for adjustment credit, which was discontinued after January 8, 2003. For further information, see www.federalreserve.gov/boarddocs/press/bcreg/2002/200210312/default.htm. The rate reported is that for the Federal Reserve Bank of New York. Historical series for the rate on adjustment credit as well as the rate on primary credit are available at www.federalreserve.gov/releases/h15/data.htm.
10. Yields on actively traded non-inflation-indexed issues adjusted to constant maturities. Source: U.S. Treasury.
11. A factor for adjusting the daily nominal 20-year constant maturity in order to estimate a 30-year nominal rate can be found at www.treas.gov/offices/domestic-finance/debt-management/interest-rate/ltcompositeindex.html.
12. Yields on Treasury inflation protected securities (TIPS) adjusted to constant maturities. Source: U.S. Treasury. Additional information on both nominal and inflation-indexed yields may be found at www.treas.gov/offices/domestic-finance/debt-management/interest-rate/index.html.
13. Based on the unweighted average of the bid yields for all TIPS with remaining terms to maturity of more than 10 years.
14. International Swaps and Derivatives Association (ISDA®) mid-market par swap rates. Rates are for a Fixed Rate Payer in return for receiving three month LIBOR, and are based on rates collected at 11:00 a.m. Eastern time by Garban Intercapital plc and published on Reuters Page ISDAFIX®1. ISDAFIX is a registered service mark of ISDA. Source: Reuters Limited.
15. Moody's Aaa rates through December 6, 2001 are averages of Aaa utility and Aaa industrial bond rates. As of December 7, 2001, these rates are averages of Aaa industrial bonds only.
16. Bond Buyer Index, general obligation, 20 years to maturity, mixed quality; Thursday quotations.
17. Contract interest rates on commitments for fixed-rate first mortgages. Source: FHLMC.

Note: Weekly and monthly figures on this release, as well as annual figures available on the Board's historical H.15 web site (see below), are averages of business days unless otherwise noted.

Current and historical H.15 data are available on the Federal Reserve Board's web site (www.federalreserve.gov/). For information about individual copies or subscriptions, contact Publications Services at the Federal Reserve Board (phone 202-452-3244, fax 202-728-5886). For paid electronic access to current and historical data, call STAT-USA at 1-800-782-8872 or 202-482-1986.

DESCRIPTION OF THE TREASURY NOMINAL AND INFLATION-INDEXED CONSTANT MATURITY SERIES

Yields on Treasury nominal securities at "constant maturity" are interpolated by the U.S. Treasury from the daily yield curve for non-inflation-indexed Treasury securities. This curve, which relates the yield on a security to its time to maturity, is based on the closing market bid yields on actively traded Treasury securities in the over-the-counter market. These market yields are calculated from composites of quotations obtained by the Federal Reserve Bank of New York. The constant maturity yield values are read from the yield curve at fixed maturities, currently 1, 3 and 6 months and 1, 2, 3, 5, 7, 10 and 20 years. This method provides a yield for a 10-year maturity, for example, even if no outstanding security has exactly 10 years remaining to maturity. Similarly, yields on inflation-indexed securities at "constant maturity" are interpolated from the daily yield curve for Treasury inflation protected securities in the over-the-counter market. The inflation-indexed constant maturity yields are read from this yield curve at fixed maturities, currently 5, 7, 10 and 20 years.

File / Crystal

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Application of SOUTHWEST GAS CORPORATION for authorization to increase its rates and charges, including revised depreciation rates, and changes in other tariff provisions for its Southern and Northern Divisions.	Docket No. 04-3011

At a general session of the Public Utilities Commission of Nevada, held at its offices on August 26, 2004.

RECEIVED

MAR 2 8 2005

AZ Corporation Commission
Director Of Utilities

PRESENT: Chairman Donald L. Soderberg
Commissioner Adriana Escobar Chanos
Commissioner Carl B. Linvill
Commission Secretary Crystal Jackson

ORDER

The Public Utilities Commission of Nevada ("Commission") makes the following findings of fact and conclusions of law:

I. Procedural History

1. On March 8, 2004, Southwest Gas Corporation ("Southwest") filed with the Commission an Application, designated as Docket No. 04-3011, for authority to increase rates and charges, including revised depreciation rates, for natural gas service for all classes of customers in Southern and Northern Nevada.

2. This Application is filed pursuant to the Nevada Revised Statutes ("NRS") and the Nevada Administrative Code ("NAC"), Chapters 703 and 704.

3. The Commission issued a public notice of this Application in accordance with State law and the Commission's Rules of Practice and Procedure.

4. On April 14, 2004, at a duly-noticed prehearing conference, the Presiding Officer granted the Petition for Leave to Intervene of the Nevada Independent Energy Coalition. The Commission's Regulatory Operations Staff ("Staff") and the Attorney General's Bureau of Consumer Protection ("BCP") participate as a matter of right.

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5. On June 1, 2004 and June 2, 2004, duly-noticed consumer sessions were held.

6. On July 12, 2004, a duly-noticed hearing was commenced.

II. Cost of Capital

A. Capital Structure

Southwest's Position

7. Theodore K. Wood, Manager of Treasury Services and witness for Southwest, testifies to Southwest's capital structure in this filing. He testifies that circumstances entirely outside of Southwest's control have prevented it from earning the Commission's approved margin revenue and rate of return in the past 10 years. These circumstances cited by Southwest include 1) a steady decline in average residential customer usage, 2) warmer than normal weather trends, 3) conservation measures, and 4) more energy efficient appliances and building construction standards. The consequences for Southwest are, compared to its peers in the natural gas industry, a lower credit rating, a low common equity ratio, and a higher risk profile. (Exhibit 8 at 16-17; Southwest Brief at 1.)

8. According to Mr. Wood, it is essential that Southwest maintain its credit rating because it is one of the fastest growing local gas distribution companies in the nation. A good credit rating and access to the capital markets is necessary for Southwest to fund its continued growth and infrastructure investment. In fact, to continue to attract capital and maintain its current investment levels, Southwest must strive to improve its credit ratings to draw potential investors away from alternative investments by offering a more competitive risk-adjusted rate of return. (Exhibit 8 at 27-28.)

9. Mr. Wood states that Southwest's declining average customer usage and warmer than normal heating seasons have resulted in a "Baa2" credit rating from Moody's Investor's Service ("Moody's") with a negative outlook[1] and a "BBB minus" credit rating from Standard and Poor's ("S&P") for Southwest. Although Mr. Wood admits these credit ratings are still

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[1] *The negative credit outlook rating by Moody's* was issued during the hearing in this case. (Tr. at 84-85.)

investment grade, he states that Southwest is on the verge of losing its investment grade rating if it does not stabilize its earnings situation. (Id. at 10-11.)

10. Therefore, for the purpose of this case, Southwest proposes the use of several interrelated mechanisms to address its declining average residential customer usage and the effects of that decline on Southwest's financial condition. One of these mechanisms is to utilize a target capital structure. According to Mr. Wood, Southwest is a diversified multi-jurisdictional natural gas company with a non-regulated subsidiary. He recommends a hypothetical, or target capital structure (see table below), to allow for the setting of rates solely for the natural gas distribution assets of Southwest, and to increase its common equity ratio for rate-making purposes so Southwest will be able to maintain its credit rating. (Id. at 8-9.)

Component	Proposed Ratios
Total Debt	53.0%
Preferred Equity	5.0%
Common Equity	42.0%
Total	100.0%

11. With regard to Southwest's target equity ratio, Mr. Wood indicates that Southwest's actual common equity ratio at 33-35 percent is well below the industry average of approximately 49 percent. Consequently, Southwest is viewed as a financially riskier[2] company by the credit agencies than its gas industry peers. He also states that despite Southwest's efforts to strengthen its capital structure by increasing its outstanding shares of common stock by 66 percent since 1993 and by not increasing its dividend since May 1994, Southwest has not been able to boost its common equity ratio due to declining residential usage. However, Mr. Wood states that even though Southwest's common equity ratio has not improved since 1993, Southwest's over-all capital structure has improved. The improvement, he states, was due to increased issuance of

[2] Credit ratings are a good business risk measure because they reflect an entity's combined business and financial risk as it compares to other firms. Within a credit rating, S&P assigns an entity a business risk position of 1 through 10, with 1 being the lowest risk. S&P determines a firm's business position by evaluating the firm's quantities and qualitative characteristics. (Exhibit 15 at 14-15.)

preferred stock (100 million shares), which improves Southwest's equity ratio and permitted all the rating agencies to rate Southwest as investment grade in 2004 when in 1991-1993 Moody's and Duff and Phelps rated Southwest below investment grade[3]. (Tr. at 32.)

12. With regard to whether the purchase of Primerit Bank in 1987 and the subsequent addition of $14.6 million to its loss reserve provisions[4] in 1992 was the cause of Southwest's low common equity ratio, Mr. Wood testifies that Southwest eventually wrote-off $14.5 million against earnings because of Primerit Bank's real estate investments. He explains that the write-off's impact on Southwest's common equity ratio was de minimis when compared to the $256 million in unrealized earnings associated with declining residential usage due to warmer weather since 1993. (Tr. at 38, 58-59.) Mr. Wood also testifies that Southwest's common equity ratio would have been approximately 47 percent at September 30, 2003, instead of in the low to mid 30's, if Southwest had realized the industry average return on common equity since 1992. (Tr. at 59.)

13. Southwest testifies that its proposed target capital structure with a common equity ratio of 42 percent is representative of a "BBB" utility[5] and will support Southwest's ability to maintain its existing "BBB" rating plus provide it with an opportunity to improve its credit rating. (Id. at 12-13.)

14. Finally, Mr. Wood discusses Southwest's request for approval of a variable interest rate recovery mechanism, as defined by NAC 704.210 to 704.222, specifically for Southern Nevada's variable rate portion of its Clark County Industrial Development Revenue Bonds ("IDRBs"). The IDRBs fund approximately 16 percent of the Southern Nevada rate base. Mr. Wood states that the approval of this mechanism will reduce the variability of Southwest's

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[3] In 1991, Moody's decreased Southwest's rating to Ba2 and in 1993 Duff and Phelps (Fitch) lowered it to BB+. (Exhibit 16 at 14.)

[4] The addition of $14.6 million to Southwest's loss reserve provisions in 1992 was due to real estate investments by Primerit. Southwest eventually had to write-off $14.5 million against earnings. (Tr. at 38 & 58.)

[5] Based on S&P's target capital ratio guidelines, Southwest's recommended hypothetical or target capital structure is representative of a "BBB" utility and not an "A" rated utility. (Exhibit 8 at 12.)

interest coverage ratio and will provide Southwest with additional capacity for new IDRBs. (Id. at 44-47.)

BCP's Position

15. BCP's witness, David C. Parcell, Executive Vice President and Senior Economist of Technical Associates, Inc., testifies to Southwest's appropriate capital structure. (Exhibit 16 at 1-2.)

16. Mr. Parcell explains that a utility's capital structure is important because the concept of rate base and rate of return regulation requires that a utility's capital structure be determined and utilized in estimating the total cost of capital. Within this framework, it is proper to ascertain whether the utility's capital structure is appropriate relative to its level of business risk and relative to other utilities. (Id. at 16.)

17. Mr. Parcell proposes using Southwest's consolidated capital structure developed from consolidating the Northern and Southern divisions' capital structures (see below). He believes the divisional capital structures more directly reflect the manner in which the Northern and Southern divisions are financed. According to Mr. Parcell, using Southwest's proposed hypothetical[6] capital structure would give Southwest a higher common equity ratio than the actual capital structure and would allow Southwest to earn an excessive return on equity. He also states that Southwest's request for a 42 percent common equity ratio should be denied because Southwest has failed to increase its common equity ratio since 1993. Furthermore, Mr. Parcell claims that Southwest's target capital structure should also be denied because using a target is an attempt by Southwest to achieve an "A" credit rating. (Id. at 21-23.)

18. During clarification questions by the Commission, Mr. Parcell explained that he considered using the actual divisional capital structure for Southwest, in addition to his consolidated capital structure, as a logical option to be included in his testimony. However, he did not offer that option ultimately, but he did indicate in his discussion with the Commission

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[6] The Commission approved a target or hypothetical capital structure in Southwest's last litigated rate case, Docket 93-3003. (Exhibit 16 at 19-20.)

that the Southern division is much more leveraged than the consolidated company, which means the Southern division is significantly more risky than the Northern division. (Tr. at 126-127.)

19. Mr. Parcell prepared a schedule (Exhibit 16 at Schedule 6), which compares the common equity ratios of four gas distribution utility industry groups to Southwest. His schedule shows that at December 31, 2003, common equity ratios for these four groups were: Value Line Group – 39.7 percent, Moody's Group – 43.4 percent, Hanley Proxy Group – 42.5 percent, and Hanley Value Line Group – 42.7 percent. Mr. Parcell agrees with Southwest that the average common equity ratio of these four groups is 42.1 percent, which is 940 basis points higher than Southwest's actual common equity ratio of 32.66 percent. He also considers this 940 basis points difference in common equity ratios to be significant. (Tr. at 78-79.) Finally, he agrees that Southwest has greater financial risk than other natural gas distribution utilities because Southwest is more highly leveraged (lower common equity ratio) than the other comparable companies. (Tr. at 95, 113.)

20. Mr. Parcell accepts Southwest's costs of long-term debt, short-term debt, customer deposits and preferred stock as appropriate for use in his proposed capital structure. (Id. at 25; Tr. at 73.)

Staff's Position

21. Ronald L. Knecht, an Economist in the Resource and Market Analysis Division and witness for Staff, testifies to Southwest's appropriate capital structure. (Exhibit 24 at 1.)

22. Mr. Knecht proposes using a hypothetical capital structure. He describes that the allowed return on equity should also take into account the capital structure that is used to set rates. Under Mr. Knecht's proposal, Southwest's capital structure and the interest rates on other long-term debt would vary with the rate base[7] used to determine Southwest's revenue requirement. Because these numbers and their averages are tied to the average capital structure of his 79 comparable companies, Mr. Knecht adjusts his modeled return on common equity using the Modigliani-Miller ("MM") hypothesis to find Southwest's return on equity for its actual

[7] The same is true under Southwest's proposed capital structure.

capital structure. By means of the MM hypothesis, Mr. Knecht seeks to demonstrate that a reasonable combination of interest rates on long-term debt and common equity can be estimated using Southwest's actual capital structure. However, Mr. Knecht recommends a 55.5 percent debt component, 1.18 percent preferred stock and capital structure of 43.32 percent common equity. (Ex. 24, p. 1-2.)

Southwest's Rebuttal Position

23. Southwest's witness, Mr. Wood, argues that using Southwest's actual capital structure[8] without a significant upward adjustment in the BCP's return on equity and subsequent overall rate of return is unreasonable. It would jeopardize Southwest's credit rating, its ability to finance its customer growth at reasonable costs, and its ability to maintain the existing quality of customer service. (Exhibit 27 at 10.)

24. Mr. Wood also states that it is not in the best interest of customers for the company to be at the lowest end of an investment grade rating. If Southwest falls below investment grade, it would lose its ability to get IDRBs, which benefits Southern Nevada customers with low cost debt. He further explains that to maintain the tax-exempt status of the IDRBs, the benefits of these bonds can only be applied to Southern Nevada's capital structure. (Tr. at 161, 164.)

25. Mr. Wood argues that Mr. Parcell's position to reject Southwest's target capital structure is based on Southwest's alleged failure to improve its capital structure; however, as his Prefiled Testimony (Exhibit 8) shows, Southwest has increased its outstanding shares of common stock by 66 percent since 1993, has not increased its dividend since May 1994, and has issued 100 million shares of preferred stock. All of theses endeavors were instituted by Southwest to improve its common equity ratio and capital structure during the past ten years. (Id. at 10-11.)

26. In addition, Mr. Wood points out that Mr. Parcell twice supported the use of a hypothetical capital structure for Southwest, each time with a common equity ratio of 40 percent.

[8] Southwest accepts Staff's proposed capital structure of 55.5 percent debt, 1.18 percent preferred stock and 43.32 percent common equity. Southwest states that Staff's ratios are very close to Southwest's proxy groups. (Exhibit 26 at 2-3.)

The rationale for Mr. Parcell's support was that the actual capital structures of Southwest's divisions reflect substantially lower common equity ratios than the typical gas distribution utility. (Id. at 5.)

Commission Discussion and Findings

27. In this case, Southwest argues significant issues about its financial health and emphasizes its decline in earnings. This is the first general rate case Southwest has filed in over 11 years in which the Commission will deliberate the issues, render decisions and provide appropriate direction. All areas of Southwest's Nevada service territory continue to grow at a significant pace which creates or exacerbates the impact of many of the issues in this case. Even though gas commodity costs are not part of this general rate case, that fact is somewhat invisible to customers who in recent years have already felt the pain of rising energy bills. The Commission believes it is particularly important under these varied circumstances to consider the issues and set policy for the benefit of the natural gas consuming public and Southwest's shareholders. Important regulatory directives from this case require Southwest to focus on certain points while supporting the solid foundation from which Southwest already operates.

28. The Commission agrees that it is important that Southwest be able to maintain its investment grade credit rating. Southwest's ratepayers will benefit from Southwest maintaining its investment grade status. An investment grade credit rating and access to the capital markets, including its ability to issue IDRBs, is a key tool for Southwest to fund the continuing growth and infrastructure investments. But Southwest must accept the appropriate responsibility for taking the measures within its control to manage its credit rating. The Commission is also responsible under NRS 704.001 to balance the interests of shareholders and ratepayers to ensure the public interest.

29. Southwest's equity ratio in its capital structure does bear on its credit rating, and Southwest's equity ratio in the low to mid-30% range is below what it should be. Southwest apparently does not disagree but the fact of the matter is that Southwest has for well over ten years maintained a relatively high debt to equity ratio, revealing a management preference for

the use of leverage. Southwest needs to address this issue. An investment grade credit rating is better supported by a higher equity ratio. Also, Southwest agreed in this case that since 1993 it has been on notice to improve its equity ratio. (Tr. p. 45) Accordingly, Southwest should take appropriate steps over a reasonable time to ensure that it increases its equity ratio.

30. While the Dividend Reinvestment Plan investors have added equity capital of approximately $50+ million annually, that level of equity infusion is insufficient to increase the equity ratio given the annual capital investment in excess of $200+ million. Similarly, if prior earnings levels have been inadequate because of warmer weather, lesser average usage per customer or other reason, the tool provided by the Legislature to remedy that is to seek rate relief. The Commission recognizes that Southwest has actively managed its costs and maintained its dividend at its current level for many years. The Commission also acknowledges that Southwest has used its discretion in not seeking frequent general rate relief, but that is the means by which Southwest's financial condition and rate adequacy is evaluated and changed. For example, the Commission is able in general rate cases to adjust rate design when appropriate to protect earnings, as it has in past cases and as it is doing in this case, in addition to updating rates based on current data.

31. Given Southwest's lower equity ratio, Southwest and Staff recommend the use of a hypothetical capital structure to set rates, and the BCP recommends use of the actual capital structure. The strongest reason to use a hypothetical capital structure is to ensure that Southwest is not disadvantaged when compared to other investment opportunities. The strongest reason not to use a hypothetical capital structure is to ensure that ratepayers only pay in their rates the actual cost of capital of the utility. The record reflects that there is little doubt that use of a hypothetical capital structure is still appropriate at this time. Nevertheless, the Commission disagrees that a percentage should be used which is as high as proposed by Southwest. However, the Commission recognizes that Southwest's revenues have suffered due to increased efficiencies and a decline in per customer usage, which will likely continue into the future. To compensate Southwest for this loss of revenues and to encourage Southwest to continue to support efficiency

gains, the Commission finds that for the purpose of setting rates in this case, an equity ratio of 40.0 percent should be used. This is only slightly below what Southwest recommended and significantly above the position expressed by the BCP, which in the past has supported a hypothetical capital structure for Southwest rate reviews. It should also be noted that this is just slightly above the actual equity ratio for the Northern Nevada division. Lastly, the Commission encourages Southwest to improve its common equity ratio in order to reduce its financial risk.

32. The Commission finds that Northern Nevada and Southern Nevada's capital structure in this proceeding should be 53.4 percent debt, 6.6 percent preferred stock and 40.0 percent common equity.

33. Finally, Southwest requests Commission approval of a variable interest rate recovery mechanism for its IDRBs. The Commission has authority to grant this recovery mechanism pursuant to NRS 704.324 and NAC 704.210. This is a reasonable step to support improvement to Southwest's financial health, and the Commission finds that Southwest's request for a variable interest rate recovery mechanism is just and reasonable and therefore approved.

B. Cost of Debt and Preferred Stock

<u>Southwest's Position</u>

34. Below are Southwest's costs for its short-term debt, customer deposits, total debt and preferred stock as of September 30, 2003.

Component	Southern Nevada	Northern Nevada
Short-term Debt	7.86 %	7.86 %
Customer Deposit	1.10 %	1.10 %
Long-term Debt	5.20 %	7.57 %
Total Debt	5.06 %	7.24 %
Preferred Stock	8.20 %	8.20 %

(Exhibit 8 at 5.)

BCP's Position

35. BCP's witness, Mr. Parcell, accepts Southwest's costs of long-term debt, short-term debt, customer deposits and preferred stock as appropriate for use in his proposed capital structure. (Tr. at 73.)

Staff's Position

36. Under Mr. Knecht and Southwest's proposal, Southwest's capital structure and the interest rates on other long-term debt would vary with the rate base used to determine Southwest's revenue requirement. (Exhibit 24 at 3.)

Commission Discussion and Findings

37. The Commission notes that BCP, Staff and Southwest agree on the costs of debt and preferred stock, all parties recognizing that the cost of debt will vary depending on the Commission's approved rate base in this case. The Commission, therefore, finds that cost of customer deposits should be 1.10 percent as of September 30, 2003, the cost of preferred stock should be 8.20 percent, and the cost of debt should be 5.07 percent in Southern Nevada and 7.16 in Northern Nevada.

C. Cost of Equity

Southwest's Position

38. Southwest's witness, Frank J. Hanley, President of AUS Consultants-Utility Services, (Exhibit 15 at 1) recommends an 11.75 percent cost of common equity, which recognizes Southwest is riskier than other relatively comparable local distribution companies ("LDCs"). (Id. at 2-3.) However, he states, if the Commission approves the proposed Margin per Customer Balancing Provision, he recommends the common equity cost rate be reduced by 25 basis points to 11.50 percent. (Id. at 2; Tr. at 66.) The recommended common equity cost rates are applicable to Southwest's proposed hypothetical common equity ratio of 42 percent. (Id. at 53; Tr. at 66.) If the Commission were to use a capital structure with a significant lower common equity ratio, his recommended common equity cost rate would be higher than 11.75 percent. (Id. at 54-55.)

39. Mr. Hanley explains that the recommended 11.75 percent common equity cost rate is based upon the application of four market-based cost of common equity models, which were all weighed equally. In order to gain an insight into the market-based common equity cost rate for Southwest, he not only applied the four market-based common equity cost rate models to Southwest but to two proxy groups of LDCs (five LDCs and eleven Value Line LDCs). The resultant proxy groups' average cost rates were adjusted to reflect Southwest's additional risk, which is evident by the proxy groups' higher credit rating and S&P assigned business position. (Id. at 3, 16, 53.) Then he averaged the three common equity cost rates to arrive at the 11.75 percent. (Id. at 56.) The results of Mr. Hanley's analysis summarized below:

	Southwest	**Proxy Group of 5 LDCs**	**Proxy Group of 11 LDCs**
Discounted Cash Flow	11.21%	10.49%	10.24%
Risk Premium	11.27%	11.44%	11.22%
Capital Asset Pricing Model	10.72%	10.97%	10.70%
Comparable Earnings	13.39%	12.70%	13.17%
Indicated Cost of Equity	11.65%	11.40%	11.33%
Investment Risk Adjustments		0.39%	0.48%
Cost of Equity after Risk Adjustments	11.65%	11.79%	11.81%
Recommendation without weather and/or volume protection		**11.75%**	

(Id. at 53; Attachment FJH-1 at 3; FJH-7 at 1; FJH-9 at 1; FJH-13 at 1; FJH-14 at 1.)

40. Mr. Hanley asserts that business risk is an important determinate in arriving at a fair common equity cost rate. For consistency with the basic financial precept of risk and return, the investor demands a reward commensurate with the risk to be taken. Southwest's business risk exceeds that of a comparable LDC. Mr. Hanley explains that while facing the same risks as other LDCs (e.g., threat of bypass, increased competition from marketers), Southwest is exposed to significant revenue and earnings volatility due to its lack of protection from declining per customer usage, which is attributable to its significant annual customer growth rate (Nevada operations experience the highest growth rate in the nation at 6 percent per annum), and is exacerbated by warmer than normal weather. He also contends that whereas Southwest lacks

protection against declines in per customer usage, a majority of each proxy group at least have protection from the vagaries of weather. Of the firms comprising the proxy group of five LDCs, three have Weather Normalization Clauses ("WNC") and one has Weather Stabilization Insurance ("WSI"). For the proxy group of eleven LDCs, six have WNC and three have WSI. (Exhibit 15 at 11-12; Attachment FJH-4 at 3; Attachment FJH-5 at 3.)

41. Mr. Hanley further explains that the decline in per customer usage in conjunction with the regulatory lag caused by the use of a historical test year has resulted in Southwest's Nevada operations achieving extraordinarily low rates of return on common equity, which is a material contributing factor to Southwest being assigned the lowest investment credit rating possible. He emphasizes that this is clearly evident by the following comparison of Southwest's Nevada operations achieved return on common equity with Moody's "Baa" utility bond yields and both proxy groups' achieved return on common equity for the period of 1997-2003:

	Northern Nevada	**Southern Nevada**	**Baa Rated Utility Bonds**	**Proxy Group of 5 LDCs**	**Proxy Group of 11 LDCs**
2003	1.43%	5.42%	6.84%	12.38%	13.08%
2002	1.38%	6.83%	8.02%	12.60%	11.49%
2001	(6.08%)	3.34%	8.03%	13.77%	12.66%
2000	(0.72%)	6.05%	8.36%	10.47%	11.05%
1999	3.80%	5.83%	7.88%	11.27%	10.99%
1998	7.44%	8.78%	7.26%	13.15%	10.14%
1997	6.07%	8.02%	7.95%	12.51%	12.58%
Average	1.90%	6.32%	7.76%	12.31%	11.71%

(Exhibit 15 at 12-13; Attachment FJH-1 at 5.)

42. While no perfect proxy exists to differentiate common equity risk between companies, Mr. Hanley opines that a credit rating provides excellent insight into common equity risk for it is the result of a thorough and comprehensive analysis of all diversifiable investment

risks. Within a credit rating, S&P will assign to a company a business position that is the result of an extensive qualitative analysis of the company's fundamental creditworthiness (business and financial risks). S&P's creditworthiness analysis for utility rating purposes considers, but is not limited to: regulatory support; earnings protection including the firm's actual earnings performance; and capital structure (e.g., debt leverage, ability to issue debt (financial flexibility). Southwest is perceived by the common equity investor as being riskier than the two proxy groups for it has been assigned by S&P a "BBB-" credit rating with a business position of four, whereas the two proxy groups each have an average S&P "A" credit rating and essentially have a business position of three (2.8 and 2.7, respectively). (Exhibit 15 at 14-15, Attachment FJH-2 at 3, 6, 8-9, 12.)

43. Further, Mr. Hanley notes that the average common equity ratio for each proxy group significantly exceeds Southwest's, 44.48 percent and 43.81 percent respectively. (Exhibit 15 at 20-21; Attachment FJH-4 at 1, 4; Attachment FJH-5 1, 5.)

44. While the selection criteria for the two proxy groups were similar, Mr. Hanley notes that the selection criteria for one group was more restrictive than the other: primarily, information had to be available from two sources (Value Line Investment Survey and ThomsonFHFirstCall), and 80 percent versus 50 percent of 2002 revenues had to have been derived from natural gas distribution operations. Additionally, in both cases, at the time of preparing his testimony, a proxy company could not have cut or omitted its cash common stock dividends during the five years ending 2002 or have been excepted to merge or be acquired. (Exhibit 15 at 16-19; Attachment FJH-4 at 2-3; Attachment FJH-5 2-3.)

45. Mr. Hanley contends that the efficient market hypothesis, the cornerstone of modern investment theory, implies that an investor will use all available models to derive the cost of common equity, for security prices reflect all the relevant information at that time. Therefore, Mr. Hanley used four common models to derive the common equity cost rate: discounted cash flow model ("DCF"), risk premium model ("RPM"), capital asset pricing model ("CAPM"), and

comparable earnings model ("CEM"). Mr. Hanley weighted each methodology equally. (Exhibit 15 at 21-25, 52-53.)

46. While acknowledging Southwest's dividend has not increased for a period of time, Mr. Hanley states that it is reasonable to assume Southwest will experience a dividend growth rate because it will have a level of earnings that will permit such an increase consistent with industry norm. Mr. Hanley employs the constant growth DCF model, which reflects that most public utilities are in a mature state of development. Further, in order to prevent an overstatement of the results, he adjusts the growth rate to acknowledge dividend rates actually changed at different times during the year and not at one point in time. In order to eliminate market volatility, the dividend yield is the average for the most recent period of time available prior to the preparation of his testimony, September through November 3, 2003. As to the growth rate, he uses forecasted earnings per share growth because this growth rate, while not accounting for all changes in market prices, is the most significant projected and historical of all accounting measure of value. This is obvious by the market reactions when earnings per share expectations are met, exceeded, or not met. Additionally, the father of the DCF model, Professor Myron Gordon indicated that earnings per share best captures investor growth expectations when trying to measure capital appreciation. (Exhibit 15 at 29-33; Attachments FJH-7, 8, and 10; Tr. at 69-70.)

47. Mr. Hanley explains that in theory the RPM model measures the additional risk associated with holding an investment in a company's common equity, which is presumed to be more risky than long-term debt, because a company's assets do not secure its common equity. As with the DCF growth rate, this model in theory assumes a constant equity risk premium when in reality the risk premium will change over time. Therefore, Mr. Hanley contends the RPM model is only valid in estimating a common equity cost rate. (Exhibit 15 at 33, 41-43.)

48. Next, Mr. Hanley estimates the long-term cost of debt by adjusting the average forecasted corporate rate "Aaa" bond interest rates for the next six quarters, ending with the first quarter of 2005, to reflect Southwest's and the proxy's groups Moody's credit rating. He

obtained the forecasted interest rates from the November 1, 2003, edition of the Blue Chip Financial Forecasts[9], and average interest rate for the Moody's "Aaa" rated corporate bond is 6.22 percent. His prospective interest rates for Southwest and the two proxy groups are 7.41 percent, 7.20 percent, and 7.10 percent, respectively. (Id. at 34-36; Attachment FJH-11at 1-4 and 7.)

49. Finally, Mr. Hanley estimates the equity risk premium by averaging: 1) a historical equity risk premium study results, which is based on Ibbotson Associates data and 2) forecasted equity risk premium, which is based upon Value Line data. His historic equity risk premium is based upon the arithmetic mean of the annual returns for S&P 500 Composite Index as compared to high-grade long-term corporate bond yields for the period 1926-2002, as reported by Salomon Brothers. He argues the arithmetic mean provides insight into potential variance and standard of deviation of returns not provided by using the geometric mean, which provided a constant return for the period. Further, Ibbotson Associates has performed empirical studies that demonstrated the use of risk premiums calculated over a short-term period distorts the RPM results. The historic analysis equity risk premiums for Southwest and the two proxy groups are 3.40 percent, 3.93 percent, and 3.93 percent, respectively. Mr. Hanley derives the forecasted equity risk premium by applying the respective beta, which reflects prospective expectations, to a prospective "A" rated public utility bond yield. The forecasted equity risk premiums are 4.31 percent, 4.55 percent, and 4.31 percent, respectively. (Id. at 36-41; Attachment FJH-11 at 1, 5-6, 8-9; Attachment FJH-12.)

50. Next, Mr. Hanley explains the CAPM model presumes that all company related risk could be eliminated through diversification, thereby leaving only market-related, or systematic, risk to be considered. Systematic risks are caused by socioeconomic events that affect the returns on all assets. The model functions by adding a risk-free rate of return to a market risk premium with the market risk premium being proportionally adjusted to reflect the company specific systematic risk. In his analysis, Mr. Hanley uses the November 1, 2003, Blue Chip

[9] The Blue Chip Financial Forecast is the consensus of forecasts from 50 economists of some renown.

Financial Forecasts yields on long-term U.S. Treasury Bonds for six quarters through the first quarter of 2005, which is 5.57 percent. He estimates the total market equity risk premium of 6.95 percent by subtracting the risk free debt rate from the Value Line forecasted total annual return of 12.52 percent for the next three to five years. This rate is similar to the 7.00 percent obtained by subtracting from the historical total annual arithmetic mean return of 12.20 percent the historic long-term U.S. Government Bond yield of 5.20 percent. While he performs the CAPM calculation using both risk premiums, Mr. Hanley's CAPM results are the average of the two CAPM calculations. (Exhibit 15 at 43-48; Attachment FJH-13.)

51. Finally, Mr. Hanley asserts that the CEM model recognizes the fundamental concept of opportunity cost, which is what an alternative investment in a similar risk option situation would yield. He argues this analysis must be applied to similar risk investments but not to other rate regulated utilities as regulatory rewards may not reflect a competitive market return and would be an exercise in circularity. In that light, Mr. Hanley derives his sample of comparatively risky non-price regulated firms by using statistics based upon market prices paid by investors over the last five years (e.g., betas), which were obtained from Value Line. (Exhibit 15 at 48-52; Attachment FJH-14.)

BCP's Position

52. BCP's witness, Mr. Parcell, recommends a return on common equity of 10 percent. This recommendation is the mid-point of a range of 9.50 percent to 10.50 percent, with the range representing the upper end results for each of his three common equity cost rate methodologies. He recommends this range as a means to "give recognition to the somewhat lower common equity ratio" that Southwest has in relation to the natural gas distribution industry in general. However, if the Commission approves one or a combination of Southwest's proposed ratemaking processes, Mr. Parcell states his recommendation would be reduced. Specifically, he recommends a reduction of 25 basis points for the Margin per Customer Balancing Provision and a 25 basis point reduction for a significant change in the monthly customer charge. Further, if both these rate proposals are accepted and Southwest is authorized to use the variable rate cost

recovery mechanism, Mr. Parcell recommends a 9 percent common equity cost rate. (Exhibit 16 at 4-5.) The following table summarizes Mr. Parcell's recommendations as to the appropriate common equity cost rate by methodology:

Methodology	Recommended Range
DCF	9.0% to 9.50%
CAPM	9.50% to 10.50%
CEM	10.50%

(Id. at 4.)

53. Mr. Parcell summarizes the two controlling U.S. Supreme Court decisions that are the legal standards for the determination of a fair rate of return. The Bluefield[10] case sets forth the requirement that the return be equal to an investment generally made at the same time and in the same general part of the country, having similar risks and uncertainties. The return should be sufficient to assure financial soundness and should, under efficient and economical management, maintain and support its credit standing and enable it to raise funds necessary for the proper discharge of its public duties. The Hope[11] case, in addition to affirming the Bluefield decision, established an "end result" doctrine, which maintains that the methods used to establish a fair return are not important so long as the end result is reasonable. Mr. Parcell interprets these decisions as authorizing the use of the three methodologies (i.e., DCF, CAPM, & CEM). (Id. at 7-8.)

54. While Mr. Parcell performs his common equity cost rate study for four proxy groups and for Southwest itself, he limits his recommendation to the results of the four proxy group studies. The four proxy groups are: Mr. Hanley's two groups, Value Line's Gas Distribution Group, and Moody's Gas Distribution Group. With the exception of the CEM model, the following table summarizes the results of his studies. Based upon his analysis, Mr. Parcell makes a generic determination that a natural gas distribution company does not need a common

[10] Bluefield Water Works and Improvement Company v. Public Service Commission of the State of West Virginia, 262 U.S. 679 (1923).
[11] *Federal Power Commission et. Al. v. Hope Natural Gas Company, 320 U.S. 591 (1942).*

equity cost rate exceeding 10.5 percent to obtain a market-to-book value ratio in excess of 100 percent.

	DCF	CAPM
Value Line Group	7.6% to 9.3%	9.6% to 10.5%
Moody's Group	6.5% to 9.1%	9.7% to 10.5%
Hanley Group of 5	8.1% to 9.1%	9.6% to 10.8%
Hanley Value Line	7.9% to 9.1%	9.6% to 10.5%
Southwest	5.70% to 13.4%	9.6 to 10.7%

(Exhibit 15 at 26, 30, 33, 38-39; Attachment 9 at 4; Attachment 11 at 1-2.)

55. Mr. Parcell acknowledges that Southwest is generally riskier than the proxy groups. This is indicated by both S&P's financial profile for Southwest, based upon the new June 7, 2004, guidelines and several other risk measures. Based upon the June 7, 2004, S&P guidelines, Southwest's business profile changed from a four to a three, and the two proxy groups changed from 2.8 and 2.7 to 2.4 and 2.3, respectively. However, S&P states that the change in scores should not be considered to represent improvement or deterioration from the previous ranking. The following is a summary of the other risk measures:

	Value Line Safety	Value Line Value Line Beta	Value Line Financial Strength	S&P Stock Ranking
Value Line Group	2.3	0.72	B+/B++	B+
Moody's Group	1.7	0.72	B++	B+
Hanley Group of 5	2.4	0.76	B+/B++	B+/A-
Hanley Value Line	2.0	0.72	B++	B+
Southwest	3.0	0.75	B	B

(Exhibit 16 at Attachment 14; Exhibit 17; Tr. at 88-89, 93.)

56. Additionally, he notes that Southwest's common equity ratio as of December 31, 2003. was significantly less than the proxy groups' common equity ratios.

	Including Short-Term Debt	Excluding Short-Term Debt
Value Line Group	39.7%	47.3%

Moody's Group	43.4%	50.0%
Hanley Group of 5	42.5%	52.6%
Hanley Value Line Group	42.7%	51.2%
Southwest	31.7%	32.9%

(Id. at 18; Attachment 6.)

57. Mr. Parcell's DCF analysis is similar to that performed by Mr. Hanley's, except Mr. Parcell uses more recent information to derive the dividend yield rate (February 2004 through April 2004) and performs the calculation using five different growth rates rather than one. He uses a combination of both forecasted dividend and earnings growth rates. Based upon this analysis, Mr. Parcell states the DCF common equity cost rate range is 9.0 percent to 9.50 percent. (Exhibit 16 at 28-30; Attachment 9.)

58. Mr. Parcell performs two CAPM model analyses to derive his recommendation. The first analysis uses the average long-term U.S. Treasury bonds yield for the period February through April 2004 as the risk free rate, which was 4.99 percent. He obtains the total market return of 12.65 percent by averaging the average S&P 500 composite group return for the period 1978 to 2002 with the average of the total return for the period 1926 to 2002, with this period's rate being the average of the arithmetic and geometric rate of returns. The second analysis uses the total returns for the period 1926 to 2003 for large company stocks as the total market return, 12.4 percent, and the historic long-term government bond yield as the risk free return rate, 5.8 percent. From this analysis, Mr. Parcell derives the range of 9.5 percent to 10.5 percent. (Exhibit 16 at 31-34; Attachment 11.)

59. Mr. Parcell contends his CEM model is a market-based methodology, because it not only compares historic return on common equity to market-to-book-value ratios but it compares forecasted return on common equity. Mr. Parcell states that a market-to-book-value in excess of 100 percent is an appropriate goal for establishing a common equity cost rate as it allows a company access to the equity market without diluting current investors value. The historic returns used are for 1992 to 2003, the last business cycle, and 1999 to 2003, the most recent five

years. His analysis indicates that historical returns in excess of 11 percent have been sufficient to produce market-to-book-value ratio in excess of 160 percent. He alludes that since the return on common equity forecasts for 2005 to 2009 are similar to historic returns, the historic market-to-book-value ratios should be indicative of future ratios. He further opines that a common equity cost rate not exceeding 10.5 percent should allow a natural gas distribution company to maintain a market-to-book-value ratio in excess of 100 percent. (Id. at 35-39; Attachment 12 and 13.)

60. Mr. Parcell agrees that generally, changes in long-term interest rates are reflected in the market required common equity cost rate. Further, he acknowledges that the Blue Chip Financial Forecast, published on July 1, 2004, indicates interest rates are expected to increase over the next six quarters (third quarter of 2004 through fourth quarter of 2005). The July 1, 2004, edition of the Blue Chip Financial Forecast's interest rate forecasts for the 20-year U.S. Treasury note and the corporate "Aaa" bonds serves as an indicator:

Period	20-Year U.S. Treasury Notes	"Aaa" Corporate Bonds
March 2004-Actual	4.79%	5.33%
April 2004-Actual	5.20%	5.73%
May 2004-Actual	5.46%	6.04%
2Q 2004 Actual	5.37%	5.94%
3Q 2004	5.6%	6.2%
4Q 2004	5.8%	6.4%
1Q 2005	6.0%	6.6%
2Q 2005	6.1%	6.8%
3Q 2005	6.2%	6.9%
4Q 2005	6.3%	7.0%

(Exhibit 18; Tr. at 95-98.)

Staff's Position

61. Staff's witness, Mr. Knecht, recommends a common equity cost rate of 10.52 percent, and opines that anything less than 10.24 percent is unreasonable. Due to the common equity cost

rate being linked to the capital structure, if the Commission uses Southwest's actual capital structure, he recommends a common equity cost rate of 11.84 percent. (Exhibit 24 at 2-3, 32; Exhibit 25 at Attachment RLK-9.)

62. Mr. Knecht testifies that his 10.52 percent recommendation contemplates the current economic conditions and Southwest's overall risk profile. Further, he contends his recommendation complies with the legal standards promulgated by the U.S. Supreme Court's decisions in Hope, Bluefield, and other applicable cases. Mr. Knecht derives the 10.52 percent common equity cost rate by averaging the results obtained from applying three methodologies, two DCF and a capital-appreciation-plus-income ("CA + I"), to a universe of 79 energy utilities (gas and electric). Further, the floor recommendation is determined by including the results obtained from applying the CAPM methodology to Southwest. The following table summarizes the results of his analysis:

Method	Result
DCF with Dividend Growth	9.41%
DCF with Earnings Retention	9.31%
CA & I	12.84%
CAPM	9.4%

(Exhibit 24 at 4-5, 7, 12, 23, 32; Attachment RLK-3 at 3; Attachment RLK-4 at 3; Attachment RLK-8 at 3.)

63. Mr. Knecht's selection of common equity cost rates estimating methodologies depends upon input data reliability and his ability to eliminate inherent limitations through implementation techniques. (Exhibit 24 at 4-7.) Through this selection process he determined that two different DCF methods and the CA & I method were available to him, with the CAPM being sufficient only to be given limited weight. (Tr. at 142-146.)

64. Mr. Knecht asserts that, consistent with his previous statistical-regression-based studies, the small differences observed between the calculated common equity cost rates for electric and natural gas companies in his universe demonstrates that speculation about differing

industry risks and returns is unfounded. Therefore, he uses as a comparable, or proxy, group for Southwest 79 energy utilities, which include both electric and natural gas companies. (Exhibit 24 at 12.)

65. Mr. Knecht performs two DCF analyses, one measuring dividend growth directly and the other indirectly through earning retention. Mr. Knecht asserts that dividend growth forecasts are a superior measure of growth than earnings forecast due to brokerage business retail operations ability to influence earnings forecasts. In these DCF analyses, Mr. Knecht utilizes a three-stage DCF model wherein the growth rate for the first stage is the company specific forecast, the second stage growth rate is a transitional rate from the first stage to the third stage rate, which is the gross domestic product growth rate. He opines that the multi-stage model is appropriate for a mature firm, since these firms go through ups and downs as start up firms. His DCF analysis includes information through June 4, 2004. Generally, he relies upon information published by Value Line. While not consensus information, Value Line is one of the most widely accepted sources of data by investors. (Exhibit 24 at 9-19; Attachment RLK-5.)

66. Mr. Knecht testifies that the CA & I model, while being subject to the same general weakness of using historical information to predict a future value, can only be overcome if the data utilized is available for an extended period of time and time discounting is employed. He utilizes his CA & I model by estimating the total return (dividends and price appreciation) then reducing this value by a risk free cost rate, which are the average long-term government bonds. Next, he time weights the annual risk premium by discounting each value by 10 percent each year. He also uses Ibbotson Associates' May 2004-forecasted long-term U.S. Treasury bond rate of 5.39 percent. (Exhibit 24 at 23; Attachment RLK-8.)

67. Mr. Knecht contends that the CAPM model is flawed because it assumes historic information is a reasonable proxy for future expectations. However, he contends that there is a better way to use historical data, such as a DCF retention-ratio technique. Mr. Knecht also notes that the historical calculated electric and natural gas industry betas have been declining since 1998 and are approaching zero, which means a common equity cost rate not be much greater

than the U.S. long-term bond rate, which is not plausible. In order to correct for this shrinkage, he notes various adjustments are questionable and are made to the historically calculated beta. Therefore, he places limited weight upon this estimating methodology. (Exhibit 24 at 21-25; Attachment RLK-7; Tr. at 142-143.)

Southwest's Rebuttal Position

68. Southwest's witness, Mr. Hanley, asserts that Mr. Parcell's DCF analysis is unreliable because it includes two firms that have cut their dividend, two firms that obtain less than 50 percent of their 2003 revenues from natural gas distribution operations firm, and one firm that does not pay a dividend. Further, the average S&P credit rating for his proxy groups is an "A" while Southwest's is a "BBB-". Therefore, an adjustment should have been made for Southwest's greater risks. (Exhibit 26 at 6-7.)

69. Mr. Hanley also argues that Mr. Parcell's application of the CAPM model is incorrect because he uses the accounting return on equity and not the market return. Further, Mr. Parcell's use of a geometric mean of the total market returns is inappropriate because it is a constant return that does not reflect the variability that actually occurs. Additionally, Mr. Hanley asserts that his risk premium methodology, which uses a beta in the calculation, is superior to the CAPM model because it represents company-specific risks. (Id. at 9-11.)

70. In addition, Mr. Hanley asserts that Mr. Parcell's market-to-book-value ratio analysis (CEM model) assumes a direct relationship between earnings and market-to-book ratios, which is not supported by academic literature or by empirical analysis. (Id. at 12-14; Attachment FJH-17.)

71. Next, Mr. Hanley argues that Mr. Knecht fails to emulate investors' behavior because he uses a non-standard multi-stage DCF model in lieu of the single stage constant growth model, and he inappropriately weighs his results (i.e., DCF two thirds) in determining his common equity cost rate recommendation. Mr. Hanley states that under the efficient market hypothesis, an investor will rely upon all models and will apply those models in a standard manner. Mr. Knecht also fails to consider Southwest as riskier than his sample group, as demonstrated by

Southwest's S&P credit rating of "BBB-" and his sample's composite S&P credit rating of "BBB+". (Exhibit 26 at 18-20.)

72. Mr. Hanley takes exception to Mr. Knecht's three-stage DCF analysis. First, he states that earnings growth estimates are a significant factor influencing stock market prices and have a greater impact than dividend growth. He concurs with Professor Gordon's comments that when buying a stock the investor is purchasing earnings, which will be received either in dividends or capital appreciation. Further, the Securities Exchange Commission has since 1999 been implementing new regulations governing research analysts that are aimed at addressing the problem referred to by Mr. Knecht. Next, Mr. Knecht's application of the three-stage model is unique as he is unaware of it being used in any other rate-setting jurisdiction. Based upon his experience, other rate-setting jurisdictions use only the single-stage constant growth DCF model. In addition, Mr. Knecht's three-stage DCF model differs from the standard model, which requires the stage one growth rate to be the company specific earning per share estimate growth rate and the second stage growth to be the industry average growth rate. Application of the standard three-stage DCF model to Mr. Knecht's proxy group, using Mr. Knecht's third stage growth rate, results in a 9.82 percent common equity cost rate. (Exhibit 26 at 21-25; Attachment FJH-20; Attachment FJH-21.)

73. Mr. Hanley argues that the CAPM model is an appropriate common equity cost rate-estimating model, as the investor under the efficient market hypothesis will use all information available in making a decision. Beta information is published by several entities, including Value Line, which Mr. Knecht notes is widely used as a source of data. The publishing entities adjust the betas for regression bias. (Exhibit 26 at 27-28; Tr. at 152.)

74. To demonstrate the need for a risk adjustment to the common equity cost rate, Mr. Hanley provides May 2004 Moody's and S&P's credit ratings for all the proxy groups:

	Moody's Credit Rating	S&P Credit Rating
Parcell's Value Line Group	A3	A-
Parcell's Moody Group	A2	A

Hanley's Group of 5	A3	A
Hanley's Value Line Group	A2	A
Knecht's Group of 79	Baa1	BBB+

(Exhibit 26 at Attachment FJH-18 at 2.)

Commission Discussion and Findings

75. The two well-recognized U.S. Supreme Court cases, Hope and Bluefield, provide the legal standards for the determination of a fair rate of return Southwest will have the opportunity to earn from its regulated natural gas distribution business. The rate of return authorized by the Commission must be comparable to that provided by other investments having similar risks and uncertainties, and must also provide Southwest with the opportunity under efficient and responsible management to maintain its financial integrity, support its credit standing and enable it to raise capital, and earn a fair return on the shareholders' investment.

76. Messrs. Hanley and Knecht both recognize that the Commission's ability to address Southwest's business risk is not limited solely to setting the authorized cost of common equity. For example, Mr. Hanley demonstrates that a company's credit rating is influenced by its common equity ratio in its capital structure, when he compares Southwest with its proxy groups' S&P credit ratings and common equity ratios.

	Common Equity Ratio	S&P Credit Rating
Southwest	31.7%	BBB-
Parcell Value Line Group	39.7%	A-
Parcell Moody's Group	43.4%	A
Hanley Group of 5	42.5%	A
Hanley Value Line Group	42.7%	A
Knecht Group of 79	43.32%	BBB+

The Commission has already addressed the issue of the appropriate equity ratio to use for the purpose of setting Southwest's rates in this case. It is important to emphasize that the Commission concurs with Staff and Southwest that Southwest's business risk is addressed in part with the authorization to use the hypothetical capital structure that includes a 40.0 percent common equity ratio in Southern Nevada and in Northern Nevada. Additionally, as will be noted in several different places in this Order, the Commission is authorizing various mechanisms in order to respond to the concern over Southwest's earnings stability. These decisions are made with the expectation that Southwest will be able to improve its earnings and realize the equity return the Commission authorizes in this decision.

77. While all parties have applied the efficient market hypothesis in the development of their recommendations, the parties differ as to the weighting to be applied by the investor to the results of any particular type of model. Southwest interprets the hypothesis to require equivalent weighting of all models. Mr. Hanley uses four models in developing his recommendation. However, the Commission observes Mr. Hanley's inclusion of two risk premium models (RPM and CAPM) in the formation of his recommendation implies a preference for the risk premium methodology. Staff and the BCP believe a weighting factor must be applied giving the DCF model greater weight. Mr. Knecht explicitly assigns the DCF model a two thirds weighting. He bases his weighting on the presumption that an investor will afford more weight to a model whose inputs are reliable. Mr. Parcell implicitly assigns a 50 percent weighting to his DCF results.

78. However, the Commission believes Mr. Knecht's lack of incorporating his CAPM model results into his recommendation is inconsistent with the efficient market hypothesis. While an investor may weigh differently the results of various cost of common equity models, the Commission agrees with Mr. Hanley that once an investor has performed an analysis the results of that analysis would be factored into the investment decision. The Commission does note that Mr. Knecht uses a self-derived beta in his CAPM model and not that published by a frequently referenced publication (e.g., Value Line). Therefore, the Commission will view Mr. Knecht's 10.24 percent cost of common equity, which includes his CAPM model results, as Staff's recommended cost of common equity.

79. A summary of Messrs. Hanley, Parcell, and Knecht's studies are contained in the following table:

	Hanley	Parcell	Knecht
DCF: Average	10.65%	9.25%	9.36%
Range	10.24% to 11.21%	9.0% to 9.50%	9.31% to 9.41%
Risk Premium: Average	11.31%	N/A	12.84%
Range	11.22% to 11.44%		N/A
CAPM: Average	10.80%	10%	9.4%
Range	10.70% to 10.97%	9.50% to 10.50%	N/A
Comparable Earnings: Avg.	13.09%	10.50%	N/A
Range	12.70% to 13.39%	N/A	

80. The Commission agrees with Messrs. Knecht and Parcell that a DCF model should be afforded more weight than the other models in developing a fair equity return for a regulated public utility, because the DCF model avoids the problems of bias introduced in using historic data. This is demonstrated by the significant variation in results derived using a similar risk premium model (i.e. Mr. Hanley's RP and Mr. Knecht's CA & I). Since Messrs. Knecht and Parcell's cost of equity recommendations give greater weight to their DCF models, the Commission believes their recommendations are superior to Mr. Hanley's. Further, the fact that Messrs. Knecht and Parcell apply three different DCF models and arrive at substantially similar results calls into question the validity of using Mr. Hanley's DCF model to establish Southwest's cost of common equity. Mr. Knecht's DCF mid-point of 9.36 percent is similar to Mr. Parcell's midpoint of 9.25 percent and his range is within Mr. Parcell's range of 9.0 percent to 9.50 percent. Mr. Hanley's DCF average is 10.65 percent.

81. While the Commission anticipates risk premium models to provide varying results, the Commission believes Messrs. Hanley and Parcell's models to be superior to Mr. Knecht's because the model results better correlate to the DCF models and their models use generally

available beta information. While Mr. Knecht's CA & I model is similar to Mr. Hanley's RPM model (both add an equity premium to an interest rate), Mr. Hanley's RPM model correlates better with his DCF model than Mr. Knecht's. Mr. Hanley's RPM model averaged 11.31 percent and his DCF model averaged 10.65 percent. Mr. Knecht's CA & I model produced a 12.84 percent and his DCF model an average of 9.36 percent. Further, Mr. Knecht's risk premium models results differ significantly from one another. Mr. Knecht's CA & I model result of 12.84 percent significantly exceeds his CAPM model results of 9.4 percent. Mr. Hanley's RPM model average of 11.31 percent is similar to his CAPM model average 10.8 percent.

82. The Commission believes Mr. Parcell's cost of common equity study under-estimates the cost of common equity. Mr. Parcell uses information for the three months of February - April, 2004. In his CAPM model, Mr. Parcell uses a 4.99 percent long-term U.S. Treasury interest rate. The evidence shows that current interest rates exceed those in affect during Mr. Parcell's study period and those used in his CAPM study (Exhibit 18). As indicated by each parties' use of risk premium models, the cost of common equity is influenced by long-term interest rates. There is generally upward pressure currently in the overall interest rate climate. Further, Mr. Parcell agrees that changes in long-term interest rates are reflected the cost of common equity.

83. , Mr. Knecht generally uses in his cost of common equity study updated information through June 4, 2004, except for the long-term U.S. Treasury bond interest rate used in the CA & I model. In his model, Mr. Knecht uses the end of December 2003 long-term U.S. Treasury bond interest rate of 5.39 percent for his analysis. His long-term U.S. Treasury bond interest rate is similar to the 5.37 percent reported for the second quarter of 2004.

84. Mr. Hanley's cost of common equity study only utilized information through September \ November 3, 2003, which is not as current as Mr. Knecht.

85. While the Commission understands that the CEM methodology in concept attempts to ascertain an investor's opportunity cost, the Commission has not, in this instance, been persuaded that the CEM methodology should be given significant weight. Mr. Hanley's CEM

results significantly exceed that of any other analysis he performed. Therefore, the Commission gives little weight to the CEM model results. Further, since Mr. Parcell's CEM estimate of 10.5 percent equal his CAPM upper range of 10.5 percent, the Commission's CEM model conclusion does not affect Mr. Parcell's 10 percent recommendation.

86. Based upon the foregoing, the Commission believes Messrs. Parcell and Knecht provide cost of common equity studies that more reasonably support a decision on Southwest's true cost of common equity. The Commission believes that there is merit to the positions expressed in both Mr. Parcell's and Mr. Knecht's cost of common equity studies. However, the Commission believes a return on common equity in excess of 10.25 percent is warranted. Since the Commission made a determination in recent general rate cases that a 10.25 percent return on common equity was reasonable, long-term interest rates have increased significantly. This trend of increasing interest rates is demonstrated by the significant increase in the U.S. Treasury 20-year note interest rates (Table on page 21). Therefore, considering the trend of increasing interest rates, the Commission finds a 10.50 percent return on common equity to be just and reasonable.

III. Revenue Requirements

A. Work Management System

Southwest's Position

87. Southwest is seeking the inclusion of the Work Management System ("WMS") in rate base. Southwest's witness, Robert J. Weaver, Southwest's Vice President/Information Service, testifies that WMS will play a significant role in Southwest's overall level of productivity because it will: 1) eliminate paperwork; 2) eliminate effort and risk of error in the distributing and filing of maps and Operations Manuals; 3) enhance work process in the field by facilitating standardization; and 4) improve work scheduling. Mr. Weaver states that this investment focuses on large-scale operational functions in construction, inspection and maintenance. WMS was closed to plant in service on June 30, 2003, at a total cost of $28,466,206. (Exhibit 32 at 10-11.)

88. Mr. Weaver submits that training employees and data conversion is part of the productive use of the WMS. (Tr. at 221.) He testifies that there is a preliminary training phase that took place earlier wherein employees were trained on the system. He explains that those employees that were initially trained then became trainers and supervisors of the majority of Southwest's employees. (Tr. at 227.) During training, the employees inputted actual work requests that became part of the Southwest's permanent records. (Tr. at 224.) During and immediately after training, the employees began using the WMS system. (Tr. at 218-219.)

89. In addition, Mr. Weaver states that data conversion started in Northern Nevada in June 2003 and was completed by September 2003. He adds that training of the facilitators and trainers was completed in August 2003, with the remaining employees trained by December 2003. (Tr. at 227-228.)

90. With regard to Southern Nevada, Mr. Weaver testifies that training and data conversion started during the December 2003-January 2004 timeframe. Data entry and training of the facilitators were completed in January 2004, with the remaining employees trained by April 2004. (Tr. at 230.)

91. Robert A. Mashas, Southwest's Director/Revenue Requirements and witness, states that the revenue deficiency impact of the WMS is $1.4 million in Southern Nevada and $0.4 million in Northern Nevada. Mr. Mashas also proposes amortizing the WMS over a 15-year period rather than the current 10-year amortization period. A 15-year amortization period decreases the revenue requirement by approximately $0.25 million for Southern Nevada and $0.06 million for Northern Nevada. (Exhibit 28 at 9-10.)

92. Jeffrey Shaw, Chief Executive Officer and witness for Southwest, acknowledges that Southwest did not make a certification filing, but he admits that Southwest had that option. (Tr. at 21.) Mr. Mashas also testifies that Southwest chose not to make a certification filing in this case. He states that Southwest did not believe it was necessary to make a certification filing since the WMS was already closed to in plant and service. (Tr. at 426.) He adds that a certification filing is a mechanism used to estimate the cost of a project that is not known at the

time of the test period. He states that in this case, Southwest knew the cost of the WMS. (Tr. at 427.)

BCP's Position

93. BCP's witness, David J. Effron, a Utility Consultant, states that the WMS was not in service in either of Southwest's divisions during the test year. Further, he notes that if Southwest wanted to include the WMS in rate base, it could have chosen a test year ending after the WMS went into service, or it could have elected to adjust its rate base and operating income in conjunction with a certification period ending after the WMS was actually in service. (Exhibit 43 at 5-6.)

94. Mr. Effron states that in the event the WMS is included in rate base, the cost of the WMS should be amortized over 15 rather than 10 years. (Id. at 23.) Further, he believes operating expenses need to be reduced to reflect the WMS productivity benefits. In that situation, he recommends a reduction of $1,064,000 in Southern Nevada and $260,000 in Northern Nevada. His adjustments include the most probable "hard dollar" savings and 75 percent of the "soft dollar" savings. (Id. at 9-10; Attachment B-1.1)

Staff's Position

95. Staff's witness, Kellie Pister, Financial Analyst, proposes that WMS be removed from rate base because it was not placed into service in Nevada until after the test period. Further, Ms. Pister states that this reduces rate base by $1,433,862 in Northern Nevada and by $5,863,993 in Southern Nevada, and reduces depreciation expense by $185,583 in Northern Nevada and $758,970 in Southern Nevada. (Exhibit 38 at 1-2).

96. Ms. Pister states that the WMS was not "used and useful" for Nevada jurisdictional purposes during the test year and that it should not be included in rate base. She claims this is supported by Mr. Weaver's statements that the WMS went into service in Northern Nevada and Southern Nevada in December 2003 and April 2004, respectively. (Id. at 2-3).

Southwest's Rebuttal

97. Mr. Weaver, witness for Southwest, contends that the WMS was used and useful in serving Nevada customers before the end of the test year and should be included in rate base. (Exhibit 50 at 1.) He submits that Southwest's corporate personnel and Nevada's Northern division employees were entering actual work requests into the WMS prior to September 30, 2003. (Id. at 3.) Further, Mr. Weaver notes that by September 30, 2003, data for Corporate and for Nevada had been loaded into the WMS database. (Id. 3-4.)

98. Mr. Weaver argues that over 90 percent of the operating expense benefits identified in the 1995 WMS strategy were employee related. (Id. at 8.) These savings have already impacted operations through management decisions made since the 1995 study. Further, 40 percent of the forecasted benefits were to be obtained through redeployment of employees not workforce reductions. (Id. at 10.) The WMS is positively affecting safety, compliance, customer service and Southwest's ability to cope with customer growth without a corresponding increase in employees. (Id. at 11.)

99. Mr. Mashas states that the WMS was transferred from Construction Work in Progress ("CWIP"), to Account 101, Gas Plant In Service – System Allocable Plan in June 2003, three months prior to the end of the test year and that the Allowance for Funds During Construction ("AFUDC") ceased as of June 30, 2003. Mr. Mashas also notes that the amortization of the WMS began July 2003. (Exhibit 52 at 3.)

100. Mr. Mashas concludes that the WMS should be allowed in rates because the cost of developing the WMS was complete in June 30, 2003. He also notes that this was three months prior to the end of the test year and 14 months prior to the effective date of rates in this proceeding. Thus, Mr. Mashas submits that Nevada employees were trained on the use of the system at least six months prior to the date that Nevada customers would begin paying for the cost of the developing of the WMS. (Id. at 9.)

101. Mr. Mashas opines that if the Commission determines a different in-service date, it would take a specific Commission directive to allow Southwest to resume AFUDC and to

postpone amortization on a post-service basis. Regardless, if the WMS is included in rate base, Southwest requests authorization of a 15-year amortization period. (Tr. at 431-433.)

Commission Discussion and Findings

102. Southwest described its roll-out of the WMS as being done one operating division at a time. Southwest states that the WMS went into service in Northern Nevada in December 2003 and in Southern Nevada in Feb. 2004. (Ex. 32, p. 6-7). For accounting purposes, the project was transferred from Work In Progress to Gas Plant in Service on June 30, 2003 when it went into service in the California division. (Id.)

103. The Commission believes the issue is whether the WMS was 'used and useful' within the test year of this case so that it can be included in the Nevada rate base. The answer to this question is governed by Nevada's long-standing utility law. Southwest's WMS was placed into service in Nevada after the close of the test year for this case. Southwest's pre-filed testimony is simple and clear in making that declaration. The Nevada law is also simple and clear. NRS 704.110(3) provides that historical, recorded expenses and investments for its most recent 12 months is the sole basis on which to change rates unless the utility also experiences and certifies additional changes for the period of 6 months beyond the original test period. Although SWG had the opportunity to make a certification filing in this case, it chose not to take advantage of this legal option, and consequently, not to bring the WMS addition into proper consideration in this case. If Southwest had made a certification filing, the test year would have been extended beyond Sept. 30, 2003, by as much as six months, and all parties agreed the WMS would then have been included in rate base as 'used and useful' plant.

104. Southwest's arguments subsequent to its pre-filed testimony fail as inappropriate attempts to twist the law into a desired result. The Commission should not be put into the position of being asked to consider these arguments especially when the Nevada law provides a complete remedy for Southwest under these circumstances. Unfortunately, for reasons that are not entirely clear and certainly not convincing, Southwest made a deliberate decision not to take the common and available step of making a certification filing to bring the addition of the WMS

into this case. Having failed to use the tools the Legislature has provided for just such situations, the Commission cannot rescue Southwest from its decision in contravention of the plain requirements of the law.

105. Southwest contends later in the case that the WMS was 'used and useful' when employee training commenced which included data entry of actual work requests. The Commission does not believe the well-recognized 'used and useful' principle of utility rate regulation is satisfied with the commencement of a somewhat lengthy process of employee training.

106. Southwest cites to Commission decisions involving Nevada Power Company ("NPC") as support for its position. First of all, each of the case decisions Southwest cited were based on the facts presented in that case, and the facts of this case are clearly distinguishable. Most importantly, NPC made certification filings capturing the results of operations for the events at issue. The WMS became used and useful in Northern Nevada in December 2003, and in Southern Nevada in the first months of 2004. These time frames are outside the test year selected by Southwest and the WMS cannot be included in the rate base for this case.

107. Southwest's proposed 15-year amortization period was uncontested by Staff and supported by the BCP; therefore, the Commission finds that WMS's amortization period should be 15-years.

B. Completed Construction, Not Classified ("CCNC")

Southwest's Position

108. Southwest's witness, Mr. Mashas, proposes that the Commission approve the inclusion of non-revenue producing CCNC items in rate base. He explains that some CCNC pipe replace dollars at the end of the test year could serve ratepayers, because Southwest does not close its CCNC work orders to plant-in-service until the entire pipeline replacement project is complete. Thus, Southwest claims that from a "used and useful" perspective, some portions of the CCNC pipeline that is replaced during the test year is currently serving the ratepayer and should be included in rates. (Exhibit 28 at 18-19.)

109. Further, Mr. Mashas explains that in order to facilitate the accounting for the costs of replacing mains Southwest will establish a work order to record and control pipeline replacement. (Id. at 18.)

Staff's Position

110. Staff's witness, Ms. Pister, recommends the removal of all CCNC for Northern Nevada and a significant portion of the Southern Nevada items. Ms. Pister testifies that these items were not placed into service until after the end of the test year and were not "used and useful" during the test year. (Exhibit 38 at 6.)

111. Ms. Pister states that if it were clearly ascertainable from Southwest's accounting records that customers were being served with replacement pipe during the test year the cost should be included in this case. However, she states that it would have to be clearly demonstrated through documentation that those parts of the project were completed prior to the end of the test year. (Tr. at 264.) Ms. Pister acknowledges that regarding the October 1, 2003, work order (Exhibit 38; Attachment No. KJP-04 at 3) Southwest clearly demonstrated that all of the customers served by that replacement line were receiving service as of September 30, 2003. (Tr. at 265-267.)

Southwest's Rebuttal Position

112. Mr. Mashas, witness for Southwest, acknowledges that in light of Ms. Pister's Attachment No. KJP-04 (Exhibit 38) Southwest no longer requests that the Commission include as CCNC the work authorizations shown on lines 2, 15, 42, 44, and 49. However, Southwest is still seeking to include non-revenue producing pipe replacement test year-end recorded expenditures in rate base. Mr. Mashas contends these expenditures were for facilities being used to serve customers by the end of the test year even though the work order will not be closed until after September 30, 2003. (Exhibit 52 at 23; Tr. at 419.)

Commission Discussion and Findings

113. The Commission agrees with Staff that if Southwest had clearly demonstrated and documented those parts of the pipeline replacement project that were used and useful during the test period it should be entitled to recovery. However, due to a lack of proper documentation, the Commission finds that Southwest is not entitled to recovery of all of its pipeline replacement costs in this proceeding. As noted by Staff, it was not clearly ascertainable from Southwest's accounting records that customers were being served with replacement pipe during the test year. The Commission encourages Southwest to adopt and implement a mechanism to track and identify those portions of the pipeline replacement project that are completed within a test year should Southwest intend to seek recovery in the future. In this way, it will be clearly demonstrated what portions have been completed.

114. The Commission notes that Staff did agree with Southwest that an October 1, 2003, work order included plant that was actually in-service on September 30, 2003. Therefore, the Commission accepts Staff's adjustment and finds that in Southern Nevada a reduction to depreciation expense of $119,063 and a reduction to rate base of $1,355,910 is appropriate, and in Northern Nevada a reduction to depreciation expense of $8,972 and a reduction to rate base of $37,348 is appropriate.

C. **Land Sale**

Staff's Position

115. Ms. Pister, witness for Staff, recommends that the gain on the sale of land in Southern Nevada at Pabco and Gibson Pressure Limiting Station be amortized over three years and included in the computation of revenue requirements. In July 2003, Southwest received net sale proceeds of $583,185 for this property that had an original cost of $375,635, and a gain of $207,550. A three-year amortization would reduce revenue requirement by $69,183. (Exhibit 38 at 5-6.)

Southwest's Rebuttal Position

116. Mr. Mashas states that Southwest did not have a dispute with Staff's adjustment with regard to the gain from the land sale in Southern Nevada. (Tr. at 418.)

Commission Discussion and Findings

117. The Commission finds that Staff's land sale adjustment of $69,183 is just and reasonable and, therefore, approved.

D. Supplemental Executive Retirement Program ("SERP") and Executive Deferred Compensation Plan ("EDCP")

Southwest's Position

118. Southwest's witness, Mr. Mashas, explains that the SERP and EDCP total account balances have not been included in rate base. In this proceeding, Southwest believes it is appropriate to include the net change in the accrued balances of SERP and EDCP from December 2, 2001, up to the end of the test year as a rate base offset. Mr. Mashas testifies that the revenue requirement impact of including the rate base offset is a decrease in Southern Nevada of $74,730 for SERP and of $88,595 for EDCP and in Northern Nevada the impact is a decrease of $20,203 for SERP and of $23,951 for EDCP. (Exhibit 28 at 21-22.) Southwest is requesting inclusion of SERP and EDCP expenses in revenue requirement. (Exhibit 2 at Statement P at 6; Exhibit 3 at Statement P at 6.)

120. Mr. Mashas explains that in Commission Docket No. 01-7023, Southwest included SERP and EDCP in the cost of service and prior to that case the related expenses were excluded from the cost of service. Therefore, the rate base offset should be limited to those amounts accrued after the end of Docket No. 01-7023's test year, thus commencing December 1, 2001. (Exhibit 28 at 14.)

BCP's Position

121. BCP's witness, Mr. Effron, proposes the exclusion of SERP and EDCP from pro forma test year operating expenses. He notes that the Commission has not made any finding that

its treatment of SERP and EDCP expenses in Docket No. 93-3003 should be modified. Mr. Effron also states that Southwest has not presented any substantive argument in this proceeding that the recoverability of SERP and EDCP should be modified, and until a formal Commission modification is made, the treatment is binding. (Exhibit 43 at 21.)

122. Mr. Effron's adjustment reduces pro forma test year operating expenses in Southern Nevada by $996,000 and in Northern Nevada by $287,000. In addition, Mr. Effron proposes reversing Southwest's rate base adjustment for Southern Nevada by $1,523,000 and by $372,000 for Northern Nevada. (Id. at 21 and Exhibit 44, Attachment B-2 and C-2.2.)

Southwest's Rebuttal Position

124. Mr. Mashas, witness for Southwest, testifies that Southwest complied with the Commission order in Docket Nos. 93-3003/93-3004 wherein the Commission ordered Southwest to prepare and file within one year a study of the management compensation by an outside firm. Also, he notes that the consultant had to be agreeable to Staff and the Office of Consumer Advocate, the BCP's predecessor. (Exhibit 52 at 11.)

125. Mr. Mashas notes that the Commission designated Docket No. 94-7023 to receive the management compensation study. Further, he states that on rehearing, the Commission did not reverse its initial decision and that Southwest requested recovery of SERP and EDCP in Docket No. 01-7023. (Id. at 12.)

126. Southwest's witness, Ms. Laura L. Hobbs, Senior Manager/Corporate Human Resources, testifies that the SERP and EDCP are part of Southwest's total compensation package. She notes that the SERP supplements the basic retirement plan ("BRP") by providing a retirement benefit to officers that is comparable to that provided to all remaining employees by removing the annual salary and benefit cap. (Exhibit 49 at 4, 7-8.) As with the SERP, she states EDCP allows officers an opportunity to defer a significant portion of salaries to the 401(k) program. Ms. Hobbs adds that the EDCP allows officers to defer portions of their salary and are eligible to defer a significant portion of salaries to the 401(k) program. (Id. at 4-6.)

127. Ms. Hobbs explains that the 401(k) plan has a dollar limitation placed on it by the Internal Revenue Service ("IRS") that does not allow an officer equal opportunity to defer compensation. Consequently, Southwest offers the EDCP to officers. It is a non-qualified plan that allows an officer to defer base salary and short-term incentive compensation. While Southwest does match contributions to the 401(k) plan, Southwest does not match any officer's contribution to the EDCP. (Id. at 6.)

128. Ms. Hobbs contends the goal of Southwest's Executive Compensation Program is to attract and retain highly qualified management and to enable management to focus on achieving specific performance objectives. (Id. at 9.) Ms. Hobbs testifies that the SERP and EDCP are reasonable and necessary costs of doing business and that the management of Southwest benefits its customers. (Id. at 11.)

Commission Discussion and Findings

129. The Commission agrees with BCP that SERP and EDCP should be excluded from operating expenses that its treatment in Docket No. 93-3003, the Commission did not allow the utility to pass the costs of SERP and EDCP on to its customers. While Southwest did provide testimony in support of the inclusion of such costs, Southwest has not presented any documentation or evidence to detail or support its SERP and EDCP benefits as reasonable other than to state that these benefits are part of its total compensation package for executives.

130. Southwest filed the compensation study in Docket No. 94-7023, which was subsequently consolidated with various dockets including 95-12015 and 95-12016, Southwest's 1995 general rate requests. Those dockets were resolved by stipulation which included this provision; "The Parties hereby acknowledge the filing of the Wyatt Study as directed by the Commission in docket 93-3003 et al. This acknowledgment shall not be construed as a validation, acceptance or other approval by any Party regarding the substantive merits of the filing." (Order 94-7023, 95-9049, 95-12015, 95-12016, 95-12017, 96-2006, 96-2007, & 96-2008 pg. 4). The status is therefore that the Commission required a study prior to approving SERP and EDCP, but because the subsequent dockets have all been stipulated, the Commission has never

considered and approved the underlying compensation study supporting the inclusion of SERP and EDCP in the revenue requirement.

131. In its Order in Docket Nos. 93-3003/3004/3005/3025/1076 the Commission stated that the executive benefits "should not be passed on to ratepayers." [12] Further, in its Order on Rehearing and Reconsideration of Docket Nos. 93-3003/3004/1076 the Commission again denied recovery of expenses related to SERP and EDCP and stated that the burden of proof and persuasion on recovery of costs lies with Southwest.[13]

132. Therefore, the Commission finds that Southwest did not provide substantial evidence to include the SERP and EDCP in operation expenses in this proceeding and agrees with BCP that the treatment of SERP and EDCP should not be modified from that in Docket Nos. 93-3003/3004. Further, the Commission orders that Southwest exclude the costs of SERP and EDCP by $996,000 in Southern Nevada and by $287,000 in Northern Nevada and reverse Southwest's rate base adjustment for Southern Nevada by $1,523,000 and by $372,000 for Northern Nevada.

E. Lead-Lag Study and Cash Working Capital ("CWC")

Southwest's Position

133. Southwest's witness, Mr. Bernard L. Uffelman, partner in the firm of Deloitte & Touché LLP, supports the lead-lag study. He notes that CWC is an amount included in rate base that represents the day-to-day cash needs of a utility, of which the lead-lag study is one component. The objective of the lead-lag study is to establish the net amount of cash supplied by investors that is not explicitly measured from a single financial account. The lead-lag study accomplishes this objective by analyzing cash flow patterns for the test year. (Exhibit 30 at 4-5; Exhibit 2 at Schedule G-5; Exhibit 3 at Schedule G-5.)

134. Mr. Uffelman testifies that depreciation and amortization are revenue requirement components that are properly includable in lead-lag studies with zero expense lead days. He

[12] Commission Order in Dockets 93-3003/3004/3005/3025/1076 at 112.
[13] Commission Order on Rehearing and Reconsideration of Docket Nos. 93-3003/3004/1076, at 11-13.

disagrees with the contention that depreciation and amortization expenses are "non-cash" items. Mr. Uffelman asserts that the inclusion of depreciation expense and amortization expense is necessary in order to allow the shareholders an opportunity to earn a return on the funds expended for plant until those funds have been received from the consumer. (Id. at 21-22.) While Southwest records depreciation and amortization expenses as being received in a particular period, Southwest will not receive the cash until some time later, as evident by the existence of accounts receivable. Therefore, he opines, Southwest is entitled to compensation for the time period these funds are held by the consumer, the average revenue lag days (i.e., 36.80 days for Southern Nevada and 36.31 days for Northern Nevada). (Id. at 23.)

135. Mr. Uffelman states that it is appropriate to include deferred federal income taxes ("DFIT") in Southwest's lead-lag study. He submits that during the period of time between when Southwest bills these costs to the time such costs are collected from customers, investors are providing the funding of DFIT and thereby sustaining utility operations. (Id. at 23-24.)

136. Mr. Uffelman states that equity return was also assigned zero expense lead days because there are no lead days associated with return on common equity, as these funds become the property of Southwest's common shareholders when the service is provided. Mr. Uffelman contends that net income available to common shareholders is effectively paid to them each day and reinvested each day until paid out to them as dividends. (Id. at 28.) As with depreciation and amortization expenses, Southwest is due compensation for the period of time the consumer holds these funds. (Id. at 28-30.)

137. Mr. Uffelman submits that the lead-lady study shows CWC provided by investors in Southern Nevada is approximately $5.776 million and in Northern Nevada it is $0.688 million.

138. Southwest also includes as a CWC component Account 135 – Working Funds, in the amount of $138,304 for the South and in the amount of $33,824 for the North. (Exhibit 2 at Schedule G-5; Exhibit 3, at Schedule G-5.)

BCP's Position

139. BCP's witness, Mr. Effron, asserts that Southwest included non-cash expenses in its lead-lag study, (i.e., depreciation, amortization, deferred taxes and the equity return). He notes that depreciation does not generate a need for cash and it is not appropriate to include the non-cash expenses in the determination of the CWC requirement. (Exhibit 43 at 11; Attachment B-2.) Further, the Commission did not include these items in NPC's recent general rate case. (Id. at 11-12.)

140. Mr. Effron testifies that removing the non-cash items from the lead-lag study would reduce the working capital allowance by $6,805,000 in Southern Nevada and by $957,000 in Northern Nevada. (Id. at 12.)

Staff's Position

141. Staff's witness, Mr. Daniel J. Gabour, Financial Analyst, proposes reductions to CWC of $4,863,980 in Southern Nevada and of $165,779. (Tr. at 242.) He states that Southwest has included a number of non-cash items in the lead-lag study that should be removed, (i.e., depreciation, amortization, deferred income taxes, and return on equity) as these items overstate Southwest's investment in funding expenses prior to receiving revenues from its customers. (Exhibit 35 at 3-4; Exhibit 36.)

142. Mr. Gabour testifies that the inclusion of depreciation, amortization and deferred income taxes violates the purpose of the lead-lag study by including expenses that require no current cash outlay by Southwest. Further, he argues that the inclusion of these expenses would result in an expansion of the lead-lag study scope to include cash flows related to construction and deferred income taxes. If such an expansion is warranted, Southwest failed to provide the additional analysis. (Exhibit 35 at 4-6.)

143. Mr. Gabour argues that be including the return on equity in the lead-lag study the utility assumes that the return on equity is advanced to the consumer by the utility and is entitled to a rate of return on those funds. He calls this the retail theory, which assumes the utility

advances all expenses and its return to the consumer and is waiting to be reimbursed for these funds. He argues that it is the customer that pays the "profit" not the investor thus it should be excluded. He asserts that the concept of the customer paying the profit is supported by the cost theory, which presumes the customer pays the return profit and all expenses, not the utility. Further, he argues that return on equity is not a component of cash flows as defined by generally accepted accounting principles. (Id. at 4, 7-8.)

144. In addition, Staff recommends adjusting CWC to include the correct interest expense lead days used in the lead-lag study and reduce both SERP and EDCP accrued liabilities included in CWC for the associated deferred income taxes. (Id. at 9.)

145. Mr. Gabour recommends the removal of Account 135-working funds, which represent petty cash and travel advances. He states that removal of working funds is necessary because the expenses being reimbursed have already been included in the lead-lag study. (Id. at 9.)

Southwest's Rebuttal Position

146. Southwest's witness, Mr. Uffelman, refutes the contention that depreciation amortization expense should be excluded from CWC. He asserts that the true issue is the recognition of the time period between the rate base deduction for these expenses and the receipt of funds from the consumer. Mr. Uffelman explains that rate base is reduced by the recorded accumulated depreciation and amortization account balances under the presumption that these funds have been recovered by Southwest. This recovery presumption is faulty, as Southwest will not receive the funds until sometime later. The revenue lag day represents the delay in recovery. (Id. at 9-11.) Mr. Uffelman also refutes the contention that DFIT should be excluded. In addition to citing the depreciation and amortization expense argument, Mr. Uffelman states that by definition it is impossible to compute anything other than zero lag days as the expense has not been paid. (Id. at 12-13.)

147. He states that the working funds represent cash on hand that are maintained by Southwest in bank accounts that have not yet been expended in support of utility operation.

Further, he asserts that it is impossible for such funds to have been expended and reflected in operating expenses in Southwest's lead-lag study. He notes that cash working funds present Southwest-supplied capital and are properly included in CWC requirements. (Exhibit 45 at 20.)

Commission Discussion and Findings

148. The Commission agrees with Staff that the purpose of the lead-lag study is to measure the amount of cash invested by Southwest to cover daily operating expenses until funds are received from the consumer. The inclusion of expenses not requiring current cash outlays (i.e., depreciation, amortization, and deferred income taxes) would overstate Southwest's cash requirements. Further, Mr. Uffelman does not disagree that depreciation, amortization, or deferred income taxes did not represent an actual cash outlay for expenses but proposes their inclusion as a means to modify the associated rate base deductions. Additionally, the Commission agrees with Staff that the customer pays the "profit" to the investor, and it is not advanced by the investor. Therefore, the Commission finds that the lead-lag study should be adjusted to exclude depreciation, amortization, deferred income tax, and return on equity.

149. In addition, the Commission notes that Southwest did not contest Staff's proposed adjustments to interest expense lead days and proposal to adjust SERP and ECDP accrued liabilities by reducing the amounts for the associated deferred income taxes. However, since the Commission is denying recovery of the SERP and ECDP program costs and associated accured liabilities, the Commission deny's Staff's adjustment to include the deferred income taxes associated with SERP and EDCP in rate base. Therefore the Commission finds that Staff's adjustments to interest expense lead days adjustments are appropriate and should be accepted.

150. The Commission is persuaded by Mr. Gabour's argument that "Account 135-working cash balances" represents expenses included in the lead-lag study and that including the balance in rate base would double count for these costs. Therefore, the Commission accepts Staff's adjustment to remove Account 135-working cash balances from rate base.

F. Service Establishment Charge Revenue

Southwest's Position

151. Southwest proposes the use of test period recorded service establishment charge revenues. (Exhibit 2 at Statement J at 2 and Exhibit 3 at Statement J at 2.)

BCP's Position

152. BCP's witness, Mr. Effron, states that as Southwest has annualized gas service revenue to reflect the year-end number of customers, the service establishment charges should also be annualized to reflect the year-end number of customers. He proposes that annualizing the service establishment charges increases pro forma test year operating revenues by $113,000 in Southern Nevada and by $1,000 in Northern Nevada. (Exhibit 43 at 19; Attachment C-1.1.)

Commission Discussion and Findings

153. BCP's adjustment was unopposed, and the Commission finds that it is just and reasonable to increase Southern Nevada and Northern Nevada's operating expenses by $113,000 and $1,000, respectively.

G. Late Charge Revenue Produced by Proposed Rates

Southwest's Position

154. Southwest proposes the use of test period recorded late charge revenues. (Exhibit 2 at Statement J at 2; Exhibit 3 at Statement J at 2.)

BCP's Position

155. BCP's witness, Mr. Effron, states that late payment charges included in total revenues should be consistent with the pro forma operating revenue, and that as the pro forma revenues resulting from rate change, the late charges should also be adjusted. His calculation of the actual late charges as a percentage of the actual revenues produced by rates in effect during the test year results in an adjustment of $549,000 to late charge revenues in the South and an adjustment of $17,000 to late charge revenues in the North. (Exhibit 43 at 17-18; Attachment C-1.1.)

156. Additionally, Mr. Effron proposes increasing Southern Nevada's late charge revenue by $100,000 related to the resolution of a $139,000 billing dispute. He estimated that the $100,000 was earned during the test year. (Id. at 18-19; Exhibit 46 at Attachment C-1.1.)

Commission Discussion and Findings

157. The Commission agrees with BCP that late payment charges included in total revenues should be consistent with the pro forma operating revenue. It is reasonable to expect that in the event revenues are greater, past due balances will be greater and the late charges will also be greater. Hence, late charges can be expected to vary directly with the level of revenues. Therefore, the Commission finds that Southwest should increase operating revenues by $549,000 in Southern Nevada and by $17,000 in Northern Nevada. Further, the Commission finds that Southern Nevada's late charge revenues should be increased by $100,000.

H. Annualized Small Commercial Gas Service Revenue and Year-end Customers

Southwest's Position

158. Small commercial customer revenues are derived from the test year adjusted number of customers and volumes. (Exhibit 2 at Schedule J-1 at 10; Exhibit 3 at Schedule J-1 at 10.)

BCP's Position

159. BCP's witness, Mr. Effron, states that Southwest's number of customers as of September 30, 2003, is affected by seasonal conditions and such conditions are not present throughout the year. He proposes that the number of customers used to annualize sales should be adjusted. Mr. Effron's calculation takes the average customer levels based on the year ended March 31, 2004, which results in an increase to adjusted test year revenue of $221,000 in Southern Nevada and $157,000 in Northern Nevada. (Exhibit 43 at 15-16.)

160. Further, Mr. Effron explains that the use of the twelve months surrounding a test year is a method for eliminating seasonality. Further, this method does not improperly reflect growth that took place after the end of the test year. (Tr. at 334.)

Southwest's Rebuttal Position

161. Southwest's witness, Mr. James L. Cattanach, Manager, Demand/Planning, states that Mr. Effron has computed average customer counts using information that extends six months beyond the end of the test year. Further, Mr. Effron failed to consider the reclassification of small commercial customers to other rate schedules. He compares recorded customer accounts to the actual September 30, 2003, count rather than the adjusted customer accounts. (Exhibit 46 at 2-3, 5.)

Commission Discussion and Findings

162. The Commission agrees with Southwest that Mr. Effron used data that extends beyond the test period ending September 30, 2003; therefore, the Commission denies BCP's annualized small commercial gas service revenue adjustment.

I. Medical Benefits Expenses

Southwest's Position

163. Southwest's witness, Ms. Randi L. Aldridge, Senior Specialist/Revenue Requirements, testifies that adjustments were made to test year recorded benefits. Ms. Aldridge states that some of Southwest's insurance premiums had significantly changed, effective with the new plan year beginning in January 2003. She notes that the test year medical costs have been adjusted to reflect the new premiums that took effect on January 1, 2003. The adjusted medical costs were calculated by annualizing September 2003 invoices. (Exhibit 29 at 17.)

BCP's Position

164. BCP's witness, Mr. Effron, states that in December 2003, Southwest adjusted the medical premiums reserve account to eliminate an over accrual. Mr. Effron submits that this adjustment was to reduce the reserve because it was determined to be over-accrued as of the end

of 2003. He argues that the over-accrual took place throughout 2003; thus, the annualized medical costs should be adjusted to eliminate the effect of this over-accrual. (Exhibit 43 at 22; Exhibit 44 at Attachment C-2.1.)

165. Additionally, Mr. Effron also proposes an adjustment to Southwest's September 2003 medical costs to reflect $15,000 in cash receipts excluded from the medical cost annualization adjustment. He states that the cash journal credits represent either reimbursement of premiums by certain inactive employees or refunds of premiums from insurance companies. And, these cash receipts should have been netted against the premiums when calculating the annualized level of insurance premiums. Mr. Effron deducts these credits from the annualized medical costs. (Id. at 22.)

166. Mr. Effron submits that his adjustments reduce pro forma expenses in Southern Nevada by $165,000 and in Northern Nevada by $64,000. (Id. at 22; Exhibit 44 at Attachment C-2.1.)

Southwest's Rebuttal Position

167. Southwest's witness, Ms. Aldridge, testifies that Mr. Effron's December 2003 related medical adjustment reaches three months outside of the test period to grab a single journal entry, booked in December 2003. The journal entry trued-up the Incurred but Not Reported claims reserve for Southwest's self-insured medical plan. The December 2003 adjustment is based upon a December 4, 2003, actuarial study. (Exhibit 47 at 13.)

168. Ms. Aldridge concurs with the BCP's cash receipts adjustment to medical expenses. She characterizes this error as an inadvertent omission. (Id. at 11.)

169. Also, Ms. Aldridge recommends that the Commission adopt all adjustments that simply correct for computational errors. In that light, Southwest is requesting that the Commission increase operating expenses in Southern Nevada by $221,983, and by $52,873 in Northern Nevada. (Id. at 12; Attachment RLA-6.) Ms. Aldridge explains that the annualized corporate staff labor adjustment reported $38,384,144 when the amount should have been $39,384,144. The difference is a typographical error, as supporting documentation demonstrates

the total is $39,384,144. (Exhibit 47 at 12; Attachment RLA-5.) The error was discovered in preparing a BCP data request and noted in the response. (Id. at 11-12; Attachment RLA-4.).

Commission Discussion and Findings

170. The Commission notes that BCP's December 2003 related medical expense adjustment is beyond the September 30, 2003, test period. Therefore, the Commission finds that this adjustment is denied.

171. Southwest acknowledges a $15,000 inadvertent omission of cash credit in the calculation of September 2003 medical expenses. Therefore, the Commission finds the medical costs for Southern Nevada shall be reduced by $34,000 and Northern Nevada by $10,000.

172. The Commission believes that as a result of a typographical error Southwest understated its annualized Corporate Labor by $1 million. The Commission finds that operating expenses in Southern Nevada should be increased by $221,983 and operating expenses in Northern Nevada should be increased by $52,873.

J. Demand Side Management Program

BCP's Position

173. BCP's witness, Mr. Effron, recommends that the remaining balance of the unrecovered DSM costs at the time rates go into effect be amortized over two years. He notes that this results in a reduction to regulatory amortization expense of $231,000 in Southern Nevada and $3,000 in Northern Nevada. Mr. Effron asserts that an adjustment to the amortization period is necessary to allow Southwest Gas dollar-for-dollar recovery of these costs without over recovering. (Exhibit 43 at 24.)

Staff's Position

174. Staff's witness, Mr. David S. Chairez, Financial Analyst, recommends a decrease in operating expense of $230,357 in Southern Nevada and a decrease of $2,995 in Northern Nevada to reflect the three-year amortization that was implemented December 1, 2001. He states that Southwest proposes the same annual amortization amounts it requested in its last general

rate case even though by the time new rates become effective in this case it will have nearly fully amortized the DSM expenditure deferral, and thus 33 of the 36 months will be amortized. Therefore, Staff is proposing that the remaining three months be amortized over three years. (Exhibit 40 at 2-3.)

Southwest's Rebuttal Position

175. Southwest's witness, Ms. Aldridge, agrees with Staff and BCP regarding the amortization of DSM balances that an adjustment should be made. Ms. Aldridge testifies that the question remaining is three years as opposed to two years amortization and she notes that two years is preferable. (Tr. at 357.)

Commission Discussion and Findings

176. The Commission finds that the existing DSM balance should be modified to be amortized for two years beyond the date of this order as proposed by the BCP and recognizes that this period is necessary to allow Southwest dollar-for-dollar recovery of costs without over recovering. Therefore, the Commission orders Southwest to reduce operating expenses in Southern Nevada by $231,000 and in Northern Nevada by $3,000.

K. Directors and Officers Liability Insurance, Leased Aircraft Liability Insurance

Southwest's Position

177. Southwest includes Directors and Officers ("D&O") liability insurance, Excess Directors and Officers liability insurance, and liability insurance for its leased aircraft. (Exhibit 2 at Schedule H-14; Exhibit 3 at Schedule H-14; Exhibit 48.)

Staff's Position

178. Staff's witness, Mr. Chairez, contends that recorded expenses for D&O liability insurance, and Excess D&O liability insurance, and liability insurance for the lease aircraft should be removed thereby decreasing operating expenses by $216,308 in the South and by $52,901 in the North. (Exhibit 40 at 2.) Mr. Chairez states that director's activities benefit both

ratepayers and shareholders. Therefore, Staff believes there should be a shared responsibility for all of the directors' costs, with the shareholder burden being the cost of D&O liability insurance. (Tr. at 288, 290.)

179. Mr. Chairez agrees that D&O liability insurance premiums are normal, recurring and reasonable business expenses. (Tr. at 289.)

180. Mr. Chairez states that while Southwest excluded its aircraft from this case, Southwest failed to exclude its aircraft related liability insurance from this proceeding, both recorded an annualization adjustment. (Exhibit 40 at 5-6.)

Southwest's Rebuttal Position

181. Southwest's witness, Ms. Aldridge, testifies that the D&O insurance premiums are reasonable expenses that are necessary to attract and maintain qualified and competent officers and directors and they provide a direct benefit to customers. (Exhibit 47 at 3.) Further, the D&O insurance is professional liability coverage that shields Southwest's officers and directors against the normal risks associated with managing the firm. It protects the personal assets of directors and officers from legal expenses, settlements or judgments, should they be sued personally, because they are covered by the D&O insurance policies. (Id. at 4.)

182. Further, Ms. Aldridge acknowledges that Southwest incorrectly annualized the prepaid aviation liability insurance and agrees with Staff that an adjustment is warranted. She states that the adjustment would be a reduction of $2,055 in operating expenses, which reduces expenses for Southern Nevada by $521 and Northern Nevada by $127. However, she demonstrated that Southwest did eliminate the recorded test year expense. (Id. at 2.)

Commission Discussion and Findings

183. The Commission believes that D&O liability insurance is a cost of doing business and recognizes that the quality and performance of Southwest's D&Os benefits ratepayers. Therefore, the Commission finds that Staff's adjustment to disallow D&O liability insurance should be denied.

184. Further, the Commission finds that insurance expenses should be reduced to remove aircraft related liability insurance in the amount of $521 for Southern Nevada and $127 for Northern Nevada.

L. Paiute Allocation

Southwest's Position

185. Southwest allocated 4.85 percent of annualized Northern Nevada costs and 4.80 percent of Southern Nevada costs to Paiute Pipeline Company. (Exhibit 2 at Schedule H-22; Exhibit 3 at Schedule H-22.)

Staff's Position

186. Staff proposes to increase Northern Nevada operating expenses by $2,665 to correct for an error in the Paiute Pipeline Company allocation ratio. Southwest uses 4.85 percent, while the correct ratio is 4.80 percent. (Exhibit 40 at 4.)

Southwest's Rebuttal Position

187. Southwest's witness, Ms. Aldridge, agrees with Staff's proposed adjustment, and notes that this is another example of data input error. (Tr. at 356-357.)

Commission Discussion and Findings

188. The Commission finds that Staff's $2,665 increase to Northern Nevada's operating expenses is just and reasonable and is, therefore, approved.

M. Sales Incentive Program ("SIP")

Southwest's Position

189. Southwest witness, Ms. Aldridge, testifies that a new SIP was implemented in the middle of the test period and that it was necessary to annualize the SIP to synchronize this component of labor with the base wages used in the labor annualization. (Exhibit 29 at 19.)

190. Southwest does not plan to annualize SIP in future proceedings. It was annualized in this proceeding because a new SIP was implemented during the middle of the test year and that made it necessary to do so at this time. (Id. at 20.)

Staff's Position

191. Staff's witness, Mr. Chairez, proposes that the Commission disallow recovery of SIP expenses as this program shares the same goals as a promotional advertising program, which the Commission has disallowed in prior general rate cases. (Exhibit 40 at 6.) Therefore, Mr. Chairez is proposing to decrease operating expenses in Southern Nevada by $247,799 and in Northern Nevada by $79,992. (Exhibit 40 at 6-7.)

Southwest's Rebuttal Testimony

192. Ms. Aldridge, witness for Southwest, testifies that the annualization of the SIP costs did not increase recorded labor costs. She notes that a decrease in operating expenses of $292,552 in Southern Nevada and a decrease in operating expenses of $185,529 in Northern Nevada is due to the annualization of SIP expenses. (Exhibit 47 at 7.)

193. Further, Ms. Aldridge states that the time of construction is the best time to get various natural gas uses into the home and that the incentive program allows Southwest's salespeople an avenue to speak with builders to make sure that natural gas uses are available to customers. (Tr. 375.)

Commission Discussion and Findings

194. The Commission believes that Southwest's SIP program provides an avenue for the company to work with homebuilders to ensure that the options to use natural gas are available, which could help reduce the usage imbalance between summer and winter seasons. The Commission also recognizes that the best time to work with builders to ensure that natural gas options are available in homes is at the time of construction.

195. The Commission also believes that Southwest is experiencing a seasonal usage imbalance in natural gas. In light of this situation, the Commission orders Southwest to make a compliance filing within six months of this Order outlining its plan to address this situation. Specifically, Southwest should tell the Commission how it would increase the summer load factor.

196. Therefore, at this time the Commission finds that Southwest's SIP program is just and reasonable and should be included in rates. Therefore, the Commission denies Staff's adjustment to remove SIP from operating expenses. Finally, after reviewing Southwest's compliance filing, the Commission will reconsider the validity of Southwest's SIP expenses.

N. Deferred Tax Asset and Net Operating Losses

Southwest's Position

197. Southwest reduces rate base for accumulated deferred income taxes in Southern Nevada by $67,458,198 and in Northern Nevada by $16,016,496. (Exhibit 2 at Statement H at 1; Exhibit 3 at Statement H at 1.)

Staff's Position

198. Staff's witness, Mr. Rex A. Bosier, Financial Analyst, recommends a $9,520,636 increase to Southern Nevada's rate base for a deferred tax asset that was recorded as a result of Southwest experiencing a net operating loss ("NOL") for federal income tax purposes in 2002 and 2003. Since the NOL was caused by plant related items (e.g., bonus depreciation), NAC 704.6526(2) requires the adjustment. (Exhibit 37 at 1; 6; Attachment RAB-3.)

Commission Discussion and Finding

199. Since the adjustment is to comply with NAC 704.6526(3), the Commission finds that Staff's adjustment to increase Southern Nevada rate base by $9,520,636 is just and reasonable and, therefore, approved.

O. Alternative Minimum Tax ("AMT")

Southwest's Position

200. Southwest includes prepaid AMT in its cash working capital in the amount of $3,838,399 in Southern Nevada and in $1,544,129 in Northern Nevada. (Exhibit 2 at G-5; Exhibit 3 at G-5.)

Staff's Position

201. Staff's witness, Mr. Bosier, recommends an increase in the prepaid AMT in the amount of $2,135,165 in Southern Nevada and $900,921 in Northern Nevada. He explains that the adjustment includes in rate base the AMT paid by Southwest for 2002 per its 2002 corporate tax return, which was filed on September 15, 2003. Pursuant to NAC 704.6542(4), AMT is to be included in rate base as a prepaid asset. (Exhibit 37 at 1, 3-4.)

202. Mr. Bosier explains that Southwest ceased recording monthly AMT estimates after June of 2003 when the balance was $25,115,337 due to the complexity of such calculations; therefore, the balance remained unchanged through the end of the test period. On September 15, 2003, Southwest filed its 2002 income tax return that showed an AMT credit carry forward of $38,680,538, which the allocation to Southern Nevada is $5,973,564 and to Northern Nevada is $2.444,650. (Id. at 5; attachment RAB-11 at 2.)

Commission Discussion and Findings

203. The Commission notes that Southwest did not rebut Staff's recommended adjustment to the AMT credit. Therefore, the Commission finds that Staff's adjustment to increase Southern Nevada's prepaid AMT balance by $2,135,165 and to increase Northern Nevada's prepaid AMT balance by $900,921 is consistent with NAC 704.6542(4) and is just and reasonable and, therefore, approved.

IV. Depreciation Study

A. General

Southwest's Position

204. Southwest's Witness, Earl M. Robinson, President and Chief Executive Officer of AUS Consultants – Weber Fick & Wilson Division, prepared and sponsors Southwest's 2004 Depreciation Study ("Study"). The Study results are included in volumes IV, V, and VI. (Exhibits 4, 5, and 6.)

205. Mr. Robinson explains that the proposed depreciation rates were developed utilizing the Straight Line Method, the Broad Group Procedure, the Average Remaining Life Technique (Exhibit 53 at 9), and that the Retirement Rate Method is the principal approach utilized to analyze Southwest's historical data. (Id. at 15.)

206. Mr. Robinson indicates that the depreciation study results reflect that changes in annual depreciation rates are warranted. Mr. Robinson is recommending an increase of $2,607,618 for Southwest's Southern Division depreciation expense, an increase of $1,489,456 for Southwest's Northern Division depreciation expense and a decrease of $1,469,701 for Southwest's System Allocable depreciation expense. (Id. at 24.)

Staff's Position

207. Staff's Witness, Frank W. Radigan, Principal in the Hudson River Energy Group, proposes adjustments to Southwest's proposed depreciation rates for the Northern Division and the Southern Division. Mr. Radigan's proposed adjustments fall into three categories: 1) accounts with meters; 2) accounts that have pipe made with poly vinyl chloride (PVC pipe); and 3) net salvage rates. (Exhibit 56 at 4). Mr. Radigan recommends that the Commission adopt his proposed Average Service Life ("ASL") values for specific accounts in the Northern and Southern Division. Mr. Radigan also recommends that the Commission accept his proposed net salvage values for the accounts that he addressed and accept the values developed by Southwest for those accounts that he did not address. (Tr. at 517, 518.)

BCP's Position

208. BCP's witness, Jacob Pous, Principal in the firm of Diversified Utility Consultants, Inc. also proposes adjustments to Southwest's depreciation rates for the Northern and Southern Divisions. Mr. Pous recommends that the Commission accept an ASL of 50 years for Account 376- Distribution Mains for both the Southern and Northern Divisions. (Exhibit 60 at 15.) Mr. Pous also states that the impact of his recommendations on Southwest's proposed rates result in a decrease in depreciation expense in the Southern Division of $2,282,483 and a

decrease in depreciation expense in the Northern Division of $868,710 for a total decrease in depreciation expense of $3,151,193.

209. Based upon review of the record, the Commission believes the disputed issues related to Southwest's Depreciation Study can be segregated into three categories. These categories include Average Service Lives - Distribution Mains and Services, Net Salvage Values and Average Service Lives – Meters.

B. Average Service Life: Distribution Mains, Services

Southwest's Position

210. For Southern Nevada, the study results indicate that the analysis of Southwest's historical data during the overall analysis band indicates an ASL of 43 years. The ASL of Distribution Mains using an experience band that includes the most recent decade is 40 years or less. Using an experience band of five years, the life indication of the property group is representative of an Iowa 40-R2.5 life and curve. (Exhibit 4 at 4-10.)

211. For Northern Nevada, the study results for the overall study period produced a life indication of thirty-eight years while recent data provides the basis for the estimated service life parameters representative of an Iowa 35-R3 life and curve. (Exhibit 5 at 4-2.)

212. Mr. Robinson lists the Company's ongoing efforts to replace PVC pipe materials as a factor affecting the proposed change in ASLs in the Northern and Southern Divisions. (Exhibit 4 at 13; Exhibit 5 at 4-2.)

Staff's Position

213. Mr. Radigan states that he does not believe the evidence presented by Southwest demonstrates a need to reduce the ASL Distribution Mains and Services accounts. Mr. Radigan disagrees with Southwest's assertion that ASLs for accounts with PVC pipe are decreasing due to the implementation of a risk-based plan. He states that Southwest does not have a risk based plan that specifically or aggressively targets the removal and early retirement of PVC pipe and that the PVC pipe was placed in service so long ago that retirements of it do not shorten its

average service life. Mr. Radigan states that the aforementioned problems with Southwest's reasoning support the use of longer service lives for the Distribution Mains and Services accounts. (Exhibit 56 at 5; Tr. at 508.)

214. In addition, he states that the statistical results of Southwest's depreciation model show that the full experience bands are better indicators of average service life than the experience bands chosen by Southwest. (Exhibit 56 at 11.)

215. Mr. Radigan recommends that ASLs based upon full experience bands be used for those accounts with PVC pipe. His recommended ASLs follow:

Southern Nevada, Account 376 – Distribution Mains, 43 years
Southern Nevada, Account 380 – Services, 41 years
Northern Nevada, Account 376 – Distribution Mains, 38 years
Northern Nevada, Account 380 – Services, 32 years

BCP's Position

216. Mr. Pous states that Southwest's proposed depreciation rate increases are driven predominantly by its proposed change in the ASL for Account 376 – Distribution Mains and therefore his testimony addresses only this issue. (Exhibit 60 at 3, 4.)

217. Mr. Pous states that an increase in the ASL of Distribution Mains, instead of a decrease, is warranted because the investment mix has changed significantly and Southwest has failed to remove atypical, abnormal, and /or unusual historical retirement activity that is not indicative of the life characteristics that will be experienced by the remaining investment in this account. (Id. at 4.)

218. Mr. Pous indicates that for the Northern Division the approximate composition of the pipe material in the Distribution mains account is 7.9 % steel, 9.9% PVC and 82.2 % PE Plastic material. For the Southern Division, the composition is 10.8 % steel, 8.1 % PVC and 81.1% PE Plastic. (Id. at 5; Exhibit 4 at 4-9; Exhibit 5 at 4-1.)

219. Mr. Pous states that Southwest's Study fails to properly recognize that the vast majority of the existing investment in its distribution mains account has a different life expectation than that reflected in its historical retirement activity. (Id. at 8.)

220. Mr. Pous believes that Southwest's proposed reduction in ASL for Distribution Mains is driven by early planned retirement of PVC investment and the development of ASL values using shorter duration experience bands. (Id. at 9, 10.)

221. Mr. Pous states that the early retirement program, a program that he states is focused on the removal of PVC pipe, should be considered as an abnormal, atypical and/or unusual historical activity. As such, an appropriate adjustment should be made to the historical data-base prior to life analysis or the final result of the life analysis if the data is included. (Id. at 11.)

222. Mr. Pous references a publication of the American Gas Association entitled, "A Survey of Depreciation Statistics." He states that from an industry standpoint, a 50 to 55-year life would represent the mid-range of the average service life used for distribution mains. He believes that Southwest's proposed ASL values for distribution mains at 35 and 40 years should be rejected unless it can be demonstrated that the life characteristics for Distribution Mains in Southwest's service territory are dramatically different than almost all other utilities. Mr. Pous does not believe that Southwest has provided such a demonstration. (Id. At 12, 13.)

223. Mr. Pous states that reliance on a 35 or 40 year ASL is misplaced because utilities have provided information that indicates that manufacturers warrant their materials for a period of up to 40 years. He further states that laboratory analysis by manufacturers have indicated that new generation plastic pipe can last for as long as 100 years.

224. Mr. Pous states that a 42-year average service life is a better indicator of the historical life characteristics for "the investment" based on data that includes the atypical or abnormal retirement activity associated with the aggressive removal of PVC pipe. However, after adjusting for the abnormal activity, he recommends a 50-year ASL for Distribution Mains for both the Northern and Southern Divisions. (Id. At 14, 15.)

225. Mr. Pous's recommendations result in a reduction in depreciation expense in the Southern Division of $2,282,483 and a reduction of $868,710 in the Northern Division.

Southwest's Rebuttal Position

226. Southwest's Rebuttal Witness, Mr. DeBonis, Director/Gas Operation in the Central Arizona Division, provides rebuttal testimony. (Exhibit 59.) Mr. DeBonis provides a description of Southwest's integrity management program and explains how this program addresses threats to the integrity of Southwest's distribution systems. (Id. at 3.)

227. Mr. Robinson clarified his position that the driver for the current experienced ASLs are both the replacement of PVC facilities and the replacement of other facilities for varied reasons. Mr. Robinson states that there was an effort to generally define a primary driver behind the life indication but it was difficult because Southwest does not report retirements by specific cause and the fact that retirements may be driven by multiple causes. (Tr. at 570, 583-84; Exhibit 62 at 4.)

228. Mr. Robinson disagrees with Mr. Radigan's testimony regarding the retirement of PVC pipe. He asserts that increased PVC pipe retirement activity will serve to lower the overall achieved ASL. He states that this circumstance lends further credence to the estimate in the Southwest's depreciation study that mains and services will continue to achieve the more recently achieved ASL values.

229. Mr. Robinson states that the determination of ASLs for a property group includes a variety of forces of retirement that cause the replacement of facilities. Accordingly, the future ASL and resulting average remaining life needs to reflect all those anticipated forces of retirement. (Exhibit 62 At 4, 5.)

230. Mr. Robinson provides plots of the ASL parameters for Distribution Mains in the Northern and Southern Divisions over a range of years. Mr. Robinson states that over the past 15-year period, the ASL for distribution mains has remained fairly constant in each Division, and it is further anticipated that this life experience will continue for a period of additional years. (Id. at 6.)

231. Mr. Robinson agrees with Mr. Pous that the type and quantity of pipe in the account does contribute to the achieved ASL but does not agree that the ASL is being driven

solely by physical material type attributes. He states that it is definitely not a fact that with the reduction of PVC Mains property, the subsequent resulting ASL will automatically increase. He states that Mr. Pous's underlying assumption that PE plastic will automatically experience a longer ASL is "conclusory" and not supported by facts. He further states that Mr. Pous's ASL recommendation is likewise significantly longer than the service lives proposed by Staff witness Frank W. Radigan. (Id. at 7, 8.)

232. Mr. Robinson states that recent years' retirement data have included considerable amounts of younger-aged non-PVC pipe retirements, demonstrating that while the PVC are contributing to the ASL indications, other non-PVC activity is also driving the ASL experience. (Id. at 9.)

233. Mr. Robinson states that Southwest's current depreciation study contains empirical evidence that Southwest has routinely experienced shorter ASLs for a considerable period of years. He states that Mr. Pous does not provide empirical data, but instead provides theoretical discussions and arguments to support his proposed 50-year average service life recommendation for Distribution Mains. (Id. at 10, 11.)

234. Mr. Robinson disagrees with Mr. Pous that the PVC pipe retirement activity for Distribution Mains is atypical, abnormal and/or unusual because the retirement activity has been going on for 15 years. (Id. at 11.)

235. With regard to Mr. Pous's discussion of industry statistics, Mr. Robinson comments that one needs to recognize when applying industry statistics to a particular system that these statistics are influenced by a variety of factors, such as the type of pipe material used. As such, the characteristics of the underlying system need to be considered as well. (Id. at 11, 12.)

Commission Findings and Discussion

236. The Commission cannot conclude that Southwest has a plan that specifically targets and results in the early retirement of PVC pipe or that this plan is influencing the ASL calculation for the Mains and Services accounts. In fact, no document was put into the record

that clearly demonstrates that Southwest is actively targeting the removal of PVC pipe. The Commission finds that Mr. DeBonis's testimony with respect to the integrity management program and how PVC pipe is addressed under this program is consistent with Mr. Radigan's testimony. (Tr. at 508; Exhibit 59 at 5.) The Commission agrees with Mr. Radigan's contention that the PVC pipe, which was installed in 1960 through 1975 and is approaching the end of its life, is as likely being retired due to age as opposed to any other reason. Therefore, the Commission finds that the retirement activity related to PVC pipe is not abnormal, atypical or unusual and should not have been removed from the historical database as suggested by Mr. Pous.

237. The Commission concludes that the testimony provided by Mr. Pous does not support the use of an ASL value of 50 years for Distribution Mains. With respect to warranty information, Mr. Pous was unable to name a manufacturer that provides a warranty, or documentation demonstrating that such a warranty is being offered by manufacturers. (Tr. at 551, 552.) He also did not demonstrate how the industry statistics he references in his testimony apply to Southwest's Southern or Northern Division. Further, Mr. Pous did not provide empirical information to support the use of a 50-year ASL for Distribution Mains.

238. The Commission is persuaded by Mr. Pous's assertion that Southwest did not appropriately consider the content, by type, of pipe material remaining in the ground when opting to use a shorter experience band. Exhibit 61 demonstrates that the majority of the retirement activity for Distribution Mains and Services in the last five years is due to the retirement of PVC pipe, yet PVC pipe constitutes only a small percentage of the pipe remaining in the ground in both Southwest's Northern and Southern Divisions. (Exhibit 60 at 5.) The Commission acknowledges Mr. Robinson's statement regarding the expected longevity of the new generation PE pipe (i.e., no one knows how long it will last). However, the Commission is convinced that the shorter experience bands used by Southwest are unduly biased because of the recent PVC pipe retirement activity and do not fairly represent the retirement activity of the general body of Distribution Mains and Services plant.

239. The Commission believes that an ASL for Distribution Mains and Services that is derived based on the full experience band bests represents the life characteristics of the remaining pipe in the ground. Therefore, the Commission finds that the full experience band should be used for determining the ASL for Distribution Mains and Services.

240. The Commission is concerned that Southwest is unable to derive from its records the factors or forces of retirement that need to be considered in determining depreciation rates. (Tr. at 458, 464, 472, 584; Exhibit 66.) The Commission believes that a more accurate estimate of rates could be developed if these factors or forces of retirement are known. Therefore, Southwest should determine what is required to adequately identify the factors and forces of retirement and submit its findings to the Commission within six months.

C. **Net Salvage Values**

Southwest's Position

241. Mr. Robinson supports the use of inflation factors in determining net salvage values. A description of the methodology used by Southwest to calculate net salvage values is provided in Exhibit 4 page 3-11 through 3-15.

Staff's Position

242. Mr. Radigan criticizes Southwest's approach to calculating net salvage values. He uses a discussion of the calculation of net salvage for the Services Account in the Southern Nevada depreciation study to demonstrate his concerns. He believes that because of the wide range of results Southwest obtained using a three-year rolling average, Southwest should have considered a wider range of rolling bands to smooth out the data. Mr. Radigan also states that Southwest's presentation of its forecast of net salvage values has been rejected by the Commission in previous cases and cites the Commission's Order in Dockets 01-10002 and 01-11031. He states that in these Orders the Commission found that if a company believes that an escalation of past results should be made, the utility must present evidence on the reasonableness of such a proposal. (Exhibit 56 at 13, 14.) Mr. Radigan supports the Commission's position

stated in these Orders and identified some factors that need to be included in such a proposal. (Tr. at 514, 515.)

243. Mr. Radigan states that he obtained Southwest's net salvage data and used a five-year and ten-year rolling band for net salvage. He reviewed the results of his analysis and written explanations provided by Southwest for each account to determine a reasonable net salvage figure. He states that for certain accounts it is clear that Southwest's approach to using mid-points and three year rolling averages is insufficient. (Exhibit 56 at 15.)

244. Mr. Radigan lists his recommendations for net salvage values for those accounts for which he has concerns and states that he is in agreement with Southwest's net salvage values for those accounts that he did not address in his testimony. (Id. at 15-19; Tr. at 517, 518.)

BCP's Position

245. Mr. Pous states that it is inappropriate to use inflation factors in the calculation of net salvage values for a number of reasons. First, there are many factors affecting the determination of net salvage values. By addressing only the inflation component of net salvage, Southwest has missed the other components that have a material affect on net salvage. Second, when inflation factors are used, ratepayers are being asked to pay with their current dollars in current rates for future inflated dollars. Finally, since historic net salvage values also include inflation, escalating historic values distorts the results. (Tr. at 545, 546.)

Southwest's Rebuttal

246. Mr. Robinson disagrees with Mr. Radigan's characterization of Commission Orders related to the use of inflation factors. He indicates that the orders simply state that, "NPC did not provide sufficient support for the application of a three percent escalation rate to the cost of removal." (Exhibit 62 at 15.)

247. Mr. Robinson opines that Mr. Radigan's net salvage proposal appears to be focused upon the average net salvage experienced as opposed to the estimated future net salvage anticipated to be experienced throughout the remaining life of the property. He further submits

that Mr. Radigan, by limiting his analysis of retirements to date, significantly understates the actual future net salvage that will be incurred throughout the life of each of Southwest's property groups. (Id. at 16, 18.)

Commission Findings and Discussion

248. The Commission is not opposed to the methodology used by Mr. Robinson for calculating future net salvage values. However, the Commission is concerned about the lack of information in Southwest's Study and in the record that addresses the value used for inflation and the other factors that were considered by Southwest in determining future net salvage values. While the Commission views Mr. Radigan's and Mr. Pous's comments on the use of inflation factors for determining net salvage values to be helpful, it would have been more useful if they had provided a more thorough summary of their analysis and evaluation of Mr. Robinson's methodology and then explained why it was flawed. If Southwest intends to use a methodology based on inflation factors in future depreciation studies, the Commission expects Southwest to include information in the study that supports the rate of inflation used as well as a summary that identifies the other factors that were considered and how these factors affected the derivation of future net salvage values.

249. The Commission finds that the net salvage values proposed by Mr. Radigan are appropriate for use in calculating the depreciation rates in this case. The Commission also finds the net salvage values developed by Southwest for accounts that are not addressed by Mr. Radigan should be used for calculating depreciation rates.

D. Average Service Life – Meters

Southwest's Position

250. Mr. Robinson states that with respect to Account 381: Meters, the overall retirements were analyzed utilizing Southwest's historical data and indicate an ASL for meters of 36 years. He further states that during the period 1996-2002, Southwest experienced increased retirements that are the product of the 1993 change in Southwest's pricing practice to include the

installation cost with the meter cost on a going forward basis. In addition, he states that Southwest's meter investment now incorporates the cost of Electronic Read Technology ("ERT") units that are not anticipated to have a service life that matches the life of the meters, with the result that the achieved life of meters may be further eroded. (Exhibit 4 at 4-14, 4-15.)

Staff's Position

251. Mr. Radigan states that in discussions with Southwest staff members, it was noted that Southwest intends to expense any replacements of the ERTs when they fail. He believes that since Southwest is expensing the only portion of the meter that has a tendency to fail that the average service life should actually increase. He states that the full experience band indicates an average service life of 36 and recommends that an average service life of 36 years be used. (Exhibit 56 at 11, 12.)

Southwest's Rebuttal Position

252. Mr. Robinson disagrees with Mr. Radigan and states that the driver for the proposed service life for Account 381: Meters was clearly not based upon the inclusion of ERTs. He further states that Southwest's depreciation study contains empirical evidence that it has experienced the average service life proposed in the depreciation study for a considerable period of years and expects such average life experience will continue. (Exhibit 62 at 14.)

Commission Findings and Conclusion

253. The Commission does not believe that Mr. Radigan provided sufficient evidence to justify a deviation from Southwest's recommended average service life for Account 381: Meters. Therefore, the Commission finds that the average service life for Account 381: Meters that is recommended by Southwest should be used in the calculation of depreciation rates for this plant account.

E. Summary of Commission's Findings

254. The Commission finds that the ASL and net salvage values included in "Attachment 1" should be used in the determination of depreciation rates.

255. The Commission finds that the annualized depreciation expenses shall be as reflected in "Attachment 2".

V. Cost of Service

A. Transmission Plant Allocation

BCP's Position

256. BCP's witness, Mr. William B. Marcus, Principal Economist for JBS Energy, Inc., testifies on cost of service and rate design issues. (Exhibit 75.) Mr. Marcus states that Southwest's cost of service study is significantly improved from previous studies in 1996 and 2001. However, he has several cost of service proposals (also see Sections B, C, and D below) for the Commission's consideration. First, Mr. Marcus proposes to allocate transmission plant 50 percent by throughput and 50 percent by peak demand in the Southern Division based on his belief that gas transmission costs are not incurred solely to meet peak load, but instead are incurred about 50/50 to meet commodity and demand. For example, he believes that gas transmission clearly has an economic value at all times of the year. As a result, his allocation method recognizes that peak use is valuable but also recognizes that a transmission system has an economic value throughout the year and should also reflect that customers are willing to pay for off-peak use of the transmission system. He claims his 50/50 commodity and demand transmission allocation reflects this. (Exhibit 75 at 18-19.)

Staff's Position

257. Ms. Anne-Marie Bellard, Manager of the Resource and Market Analysis Division and witness for Staff, states that Southwest's cost of service study adequately allocates costs among customer classes in the case. (Exhibit 78 at 7.)

258. She agrees with Southwest that transmission plant must be sized to meet maximum demand and therefore, it should be allocated 100 percent to demand as Mr. Gieseking did in his cost of service study. (Tr. at 665-666.)

Southwest's Rebuttal Position

259. Mr. Edward B. Gieseking, Director of Pricing and Tariffs and witness for Southwest, testifies to cost of service and to the Margin per Customer Balancing Provision ("MCB"). (Exhibit 69; Exhibit 86.)

260. Regarding transmission plant allocation, Mr. Gieseking has allocated the cost of transmission to the customer classes based on each class' coincident peak demand, which follows the cost causation principle that transmission mains are designed and constructed to meet the peak day demands of all customers. This allocation (100 percent to demand) reflects how costs are, and continue to be, incurred on Southwest's system. In addition, Mr. Gieseking points out that the Commission previously rejected Mr. Marcus' 50/50 transmission allocation proposal and accepted Southwest's peak demand methodology in Docket 01-7023 (the last general rate case). (Exhibit 86 at 27-28.)

Commission Discussion and Findings

261. The Commission agrees with Southwest and Staff that peak day demand includes the level of capacity needed to meet customers' annual throughput and that an allocation based on annual throughput similar to Mr. Marcus' proposal would punish the customer classes that use their allocation peak day capacity more efficiently. Therefore, the Commission finds that Southwest properly allocated transmission plant in its cost of service study.

B. Distribution Mains Allocation

BCP's Position

262. BCP's witness, Mr. Marcus, recommends in his second cost of service proposal, allocating distribution mains into three cost classifications (demand, customer and commodity). Under his proposal, facilities with a close nexus to serving a customer are assigned to that customer, while facilities at a greater distance are treated like primary distribution facilities (similar to an electric utility). In Southern Nevada, his method of allocation classifies mains as 45.05 percent customer, 48.62 percent demand and 6.33 percent commodity. In Northern

Nevada, mains are classified as 32.48 percent customer, 62.61 percent demand and 4.92 percent commodity. (Exhibit 75 at 22-24.)

Staff's Position

263. Staff's witness, Ms. Bellard, testifies that the Commission ordered Southwest in Docket 01-7023 (the last general rate case) to allocate distribution mains 50/50 to customers and to demand. She states that the Commission's decision was reasonable in that case and is still reasonable in this case. (Tr. at 665.)

Southwest's Rebuttal Position

264. Mr. Gieseking states that BCP's approach is incorrect and introduces a much more complicated classification methodology than his proposal. He also states that Southwest's investment in distribution mains is not driven by the throughput on its distribution system as Mr. Marcus claims. (Exhibit 86 at 21-22.)

Commission Discussion and Findings

265. The Commission agrees with Ms. Bellard that the Commission's previous decision in Docket 01-7023 was reasonable and that it is still reasonable and relevant in this case. Therefore, the Commission finds that Southwest properly allocated distribution mains in its cost of service study.

C. **Allocation of Late Charges**

BCP's Position

266. In his next cost of service proposal, Mr. Marcus allocated revenues from late charges based on the classes that actually pay the charges versus Southwest's allocation based on late charges in proportion to total revenue. (Exhibit 75 at 26.)

Southwest's Rebuttal Position

267. Mr. Gieseking agrees that Mr. Marcus' methodology to allocate late charge revenues is a refinement of Southwest's methodology, however, he states the data required to perform Mr. Marcus' allocation by rate class is not available. (Exhibit 86 at 25.)

Commission Discussion and Findings

268. The Commission believes that to the extent Southwest can refine its late charge revenue allocation consistent with Mr. Marcus' proposal, Southwest should make the refinement. If the data is not available, Southwest should use its cost of service study in this filing to allocate the late charge revenues, but it should explain to the Commission in the next general rate case why the data is not available.

D. Other Minor Cost Allocation Adjustments

BCP's Position

269. Finally, Mr. Marcus proposes two additional minor adjustments to Southwest's cost of service study. First, he proposes to allocate O&M expenses of the Southern Nevada transmission metering and regulating stations by plant, thus allocating more costs to special contracts to reflect the large block of directly assigned plant. Finally, he proposes to allocate customer advances by the sum of mains and services rather than system-wide gross plant. (Exhibit 75 at 26.)

Southwest's Rebuttal Position

270. Mr. Gieseking explains that Southwest allocates both distribution and transmission metering and regulating station expenses based on throughput. He states that these expenses are attributable to the volume of gas flowing through the facilities. He claims that BCP's allocation is inconsistent with the data and violates the cost causation principles used by Southwest in its cost of service study. (Exhibit 86 at 24-25.)

271. Regarding customer advances, Mr. Gieseking clarifies Mr. Marcus' assertion that Southwest allocates these costs on system-wide gross plant. He states that Southwest, in fact, allocates these costs based on net plant. Nevertheless, Mr. Gieseking does not oppose Mr. Marcus' proposal to allocate customer advances on net Mains and Services Plant. (Exhibit 86 at 25.)

Commission Discussion and Findings

272. The Commission believes in using cost causation principles in allocating costs where practical. Therefore, the Commission finds that Southwest correctly allocated its transmission metering and regulating station expenses in its cost of service study. The Commission also finds that Southwest should allocate customer advances on net Mains and Services Plant as Mr. Marcus proposes.

273. Regarding the remainder of Southwest's cost of service study not addressed above, Staff agrees that Southwest's study is an appropriate means to allocate class cost responsibility. (Exhibit 78 at 7.) Mr. Marcus, on the other hand, states that Southwest's study is a significant improvement over previous cost of service studies, but he had several concerns, which were all addressed by the Commission above. (Exhibit 75 at 18.) Therefore, the Commission finds that the remainder of Southwest's cost of service study, not addressed above, is just and reasonable and approved.

VI. Rate Design

A. Margin Per Customer Balancing Provision ("MCB")

Southwest's Position

274. Mr. Gieseking testifies that an MCB decouples Southwest's residential non-gas (margin) revenue recovery from the volume of gas delivered in a given month and re-couples margin revenue recovery to the number of residential customers served each month. An MCB, he claims, protects residential customers against margin over-collections and protects Southwest against margin under-collections due to differences between adopted test year residential consumption per customer and consumption per customer experienced in future periods. This is accomplished through the establishment of a balancing account that records the difference between authorized margin per customer and actual billed margin per customer on a monthly basis. Periodically the balance in the account would be returned or recovered from ratepayers. An MCB, according to Mr. Gieseking, would have no effect on the economic incentives for gas customers to pursue conservation and energy efficiency because the best incentive to conserve is

the savings in purchased gas costs that customers obtain when their usage decreases. (Exhibit 69 at 3.)

275. Mr. Gieseking testifies that an MCB, which decouples revenues from volume of sales, is necessary because sales per customer have been decreasing significantly in recent years due to warmer weather on average, due to installation of conservation measures, and due to more energy efficient appliances and building construction standards. (Id. at 4.)

276. Mr. Gieseking also states that an MCB does not guarantee Southwest's authorized rate of return. According to Mr. Gieseking, Southwest's profitability is dependent on the difference between the authorized margin per customer and the expenses incurred to provide service. Therefore, an MCB continues to provide Southwest incentive to operate as efficiently as possible by keeping expenses as low as possible. (Id. at 6.)

BCP's Position

277. Mr. Marcus does not support Southwest's proposal for an MCB; however, he does not oppose the use of an MCB in principle. (Tr. at 653.) Instead, in this case he recommends a weather-normalization mechanism[14], as a matter of policy, to reduce Southwest's risk. Mr. Marcus does not dispute Southwest's contention that customer sales are declining due to warmer weather, but BCP claims the rate of decline in sales has slowed in recent years and that if Southwest uses a weather normalization mechanism coupled with BCP's proposed reduction in line extension allowances[15] to developers, Southwest's declining margin revenue problem would be solved. (Exhibit 75 at 13.) However, on cross-examination, Mr. Marcus did agree that a weather-normalization mechanism would not prevent a continued decline in Southwest's margin revenues if existing customers use less gas due to conservation or other non-weather related factors. (Tr. at 652.)

[14] BCP believes, as a matter of law, that the adoption of an MCB or weather normalization mechanism would first require a rulemaking procedure by the Commission.

[15] BCP claims that Southwest's revenue requirement, in part, is driven by plant increases caused by overestimating line extension allowances to developers (new customers are not paying for their full line extension costs, thereby causing new plant additions not covered in rates...not in rate base, therefore, the need for a rate increase). However, he agrees with Southwest that his recommendations on line extensions should only be instituted in a future proceeding. (Tr. at 650.)

Staff's Position

278. Staff members oppose an MCB for various reasons. Mr. Chairez testifies to the numerous accounting and auditing issues that must be resolved before Staff could support an MCB[16]. Among the issues Mr. Chairez identifies are: 1) the disposition of the accrued balance when Southwest files a future GRC and new MCB rates are set; 2) whether carrying costs should be calculated on an MCB balance; 3) the magnitude of a potential MCB rate relative to the margin rate; 4) whether an MCB rate has the potential to accrue a credit balance overtime as opposed to only accruing a debit balance; 5) whether an MCB provision should only apply to residential customers; and, 6) the appropriateness of a monthly MCB mechanism. (Exhibit 40 at 10.)

279. Ms. Bellard points out in Attachment AMB-04 to Exhibit 78 that Southwest's ability to implement an MCB is subject to the Commission's approval. Furthermore, AMB-04 includes the minutes of the Assembly Committee on Commerce and Labor's general discussion on this deferred accounting mechanism, which specifically states that "…this balancing or deferred account treatment [is] for a specific program if and when a natural gas utility applied…" Therefore, Ms. Bellard points out that this mechanism is only for a specific or limited program and not for an MCB, which is more permanent. (Exhibit 78 at 2.)

280. In addition, Ms. Bellard testifies that the proper forum for Southwest to recover its increasing costs or decreasing revenues is in a general rate case. In a general rate case, the Commission establishes Southwest's rates based on the most current financial information, customer sales information, and weather information available. She also explains that Nevada statute allows a utility to counter regulatory lag by updating its test period costs with a certification period, which extends six months beyond the end of the test period. She notes that Southwest declined to take advantage of this statute and did not update its test period costs with a certification period. (Exhibit 78 at 3-4.)

[16] Staff calls Southwest's MCB a Margin Revenue Balancing Account (" MRBA") to avoid the confusion of the letters "MC", *which usually refer to "Marginal Cost" not marginal customer as the Company is currently using the* term. (Exhibit 78 at 3.)

281. Finally, Ms. Bellard testifies that an MCB appears to be a mechanism to *guarantee* the utility's authorized rate of return rather than give the utility an *opportunity* to earn its authorized rate of return. But on cross-examination, Ms. Bellard agrees with Southwest that an MCB does not, by itself, guarantee Southwest will achieve its rate of return, rather an MCB makes it more likely that Southwest will achieve its authorized rate of return than under traditional rate design methods. (Id. at 4 & Tr. at 675.)

Southwest's Rebuttal Position

282. Mr. Gieseking addresses Staff's accounting and auditing issues in his rebuttal testimony. He explains that an MCB balance (debit or credit) would be cleared annually similar to Southwest's deferred balance in its purchased gas cost adjustment filing; that carrying costs should be applied to the balance because the balance represents amounts owed either to customers or to shareholders; and, that the MCB would apply only to residential customers because the MCB is more equitable to a larger, more homogeneous group of customers (residential) that has no separate demand component[17]. (Exhibit 86 at 11-20.)

283. He also disputes Staff's analysis that the MCB will only produce large debit balances to be collected from ratepayers. Mr. Gieseking explains that Staff's analysis used the rate design authorized in Docket 01-7023; however, if Southwest's proposed rate design[18] is used with the MCB analysis, Staff's calculated unrecovered margin is decreased by more than half. (Id. at 15 & EBG-5.)

284. Mr. Gieseking discusses Ms. Bellard's belief that Southwest should address its declining margin revenue in a general rate case rather than with Southwest's proposed MCB. He counters that it is the Commission's responsibility to consider the MCB in its determination of risk and responsibility to Southwest and to its customers due to declining margin revenue. He also explains that even if the Commission authorized the MCB, Southwest's internal business risk would not be eliminated. Mr. Gieseking maintains that Southwest must still control its

[17] Southwest's largest general service customer's rates, for example, are designed with a demand charge.
[18] Southwest's proposed rate design and MCB were developed to complement each other. (Exhibit 86 at 15.)

expenses and properly manage its assets to earn its authorized rate of return. The MCB would only reduce the external business risk (risk beyond Southwest's control) of warming weather trends and customer conservation. Therefore, according to Mr. Gieseking, the MCB does not *guarantee* Southwest its authorized rate of return. (Id. at 8-9.)

Commission Discussion and Findings

285. There can be no question that establishing the MCB as proposed by Southwest would be a significant change from current practices. Before a significant change is authorized, the Commission must be able to arrive at the conclusion that the proposed change is the right thing to do to address the perceived problem. The Commission cannot conclude that the evidence is compelling to establish the MCB, especially prior to using other more recognized alternatives. Consequently, the Commission is not prepared to amend Southwest's billing practice in such a drastic manner at this time.

286. The Commission understands the simplicity of Southwest's concern that usage volatility – for whatever reason- could be resolved by a balancing account type response. However, historically, that has been reserved for large and unpredictable costs such as the wholesale natural gas commodity. The Legislature has provided flexibility with the recent statutory amendment, but it is Staff's recommendations that NRS 704.185(3) be read more narrowly so as not to support the MCB. Nevertheless, the statute is clear that it is within the Commission's discretion as to the type of balancing accounts for which this authorization is given. In this Order, the Commission is choosing alternative methods to assist with stable earnings such as the hypothetical capital structure, the variable interest rate recovery mechanism, the increase to the basic customer charge, its encouragement to use more frequent rate filings with certifications for updating information as necessary, and the overall rate design.

287. General rate cases allow the Commission to establish new rates based on the most current financial and customer sales information. Nevada law allows a utility to mitigate regulatory lag by updating its test period costs with a certification period. If Southwest utilizes these tools, coupled with the other benefits mentioned above, the Commission expects to see an

improvement in the level and stability of Southwest's earnings. Southwest can re-evaluate the statutory authority and the need for an MCB approach after the benefits of these alternatives are experienced and evaluated.

288. Staff and BCP also recommend a weather-normalization mechanism to address declining margin revenue associated with warming, average weather trends, but neither party specified what or how this mechanism would be or would operate. Therefore, the Commission will not comment on Staff and BCP's recommendation for a weather-normalization mechanism.

B. Rule 9 and 10 Customer Allowance

BCP's Position

289. BCP claims that Southwest's revenue requirement, in part, is driven by plant increases caused by overestimating line extension allowances to developers. For example, new customers are not paying for their full line extension costs, thereby causing new plant additions for Southwest that are not covered in rates. New plant investment that is not in rate base or rates would require a general rate case and subsequent revenue increase. Mr. Marcus calculated a rate base adjustment based on line extension job samples, however, he agrees with Southwest that his recommendations on Rule 9 and 10 line extensions should only be instituted in a future proceeding. (Tr. at 650 & BCP Brief at 34.)

Staff's Position

290. Staff recommends lowering the Rule 9 and 10 customer line extension allowance from five-times margin to four-times margin. Staff believes this will benefit Southwest due to its explosive growth in residential service investment by requiring an increased contribution from those customers causing the growth. According to Staff, this will also alleviate the disparity between revenue and plant investment costs. (Exhibit 78 at 7.)

291. On cross-examination, Staff agrees with Southwest that a margin that is sufficient to cover the financing costs (which includes debt, preferred stock, common equity, and tax on equity), depreciation expense, and property taxes of the mains and services extended to a new customer would pay for itself over some period of time. (Tr. at 668-669.)

Southwest's Rebuttal Position

292. Mr. Mashas explains how Southwest calculates its residential Rule 9 and 10 margin[19], which at five-times margin is sufficient to cover the financing costs (debt, preferred stock, common equity, and tax on equity) of mains and services plus the depreciation expense and property taxes. In addition, five-times margin also supplies enough extra funds to cover metering and incremental operating and customer accounts expense. (Exhibit 52 at 16 & 18.)

293. On cross-examination, Mr. Mashas states that five-times margin has been in Southwest's Southern Nevada Rule 9 and 10 tariff for over 20-years and in Northern Nevada's Rule 9 and 10 tariff since Docket 01-7023 when it was changed from three-times to five-times margin. (Tr. at 753-754.)

Commission Discussion and Findings

294. The Commission agrees with Southwest and BCP that any changes to Southwest's Rule 9 and 10 should be decided in a future proceeding. Furthermore, the Commission notes that Staff also recognizes that if Southwest's funds from its margin are sufficient to cover the line extension over some period of time, then its margin is correct. Therefore, the Commission will not change Southwest's Rule 9 and 10 customers' line extension allowance (five-times margin) at this time. Lastly, the Commission encourages Southwest, Staff, and the BCP offer a proposal that examines the five times margin criteria and that considers a four times margin.

C. **Basic Service Charge**

Southwest's Position

295. A. Brooks Congdon, Manager Pricing and Tariffs at Southwest, proposes rate design changes that maximize Southwest's movement towards cost-based rates. He justifies this move toward cost based rates because virtually all of Southwest's gas distribution system costs are "fixed" costs, which do not shrink in the short-run when usage declines. (Exhibit 74 at 9-10.)

[19] The annual margin is determined by adding the annual basic service charge to the product of the estimated therms (which is determined by multiplying the expected used for each appliance by the number of alliances) multiplied by the margin rate per therm. (Exhibit 52 at 15-16.)

296. Under Southwest's rate schedules, Mr. Congdon proposes a seasonal daily basic service charge with lower average per therm charges during winter months when the average usage for residential customers peaks. He proposes seasonally differentiated daily basic service charge amounts to help minimize the impact of higher average per therm basic service charges in the summer when average use is much less than during the winter months. The impact of higher basic service charges are further reduced by using declining, block rates with the second block recovering 100 % of the demand and commodity related costs. (Id. at 13.)

BCP's Position

297. Mr. Marcus recommends against adopting Southwest's basic service charge for two reasons even though he advocates gradualism[20] for all customer classes. First, it creates very large rate increases for small users because of the large increases in fixed charges and the rate decrease in the declining block. Next, it provides a dramatic reduction in the Company's risk by increasing fixed charges and reducing variability in rates with respect to usage. (Exhibit 75 at 33-34)

298. Mr. Marcus recommends that if the Commission considers increasing Southwest's customer charge, it should only include costs directly related to customers without including more common costs such as mains and A&G. (Id. at 42.)

Staff's Position

299. Staff believes Southwest's seasonal daily basic service charge proposal is overly complex, but it believes some elements could be implemented to accomplish Southwest's goal of moving more towards cost based rates. Nevertheless, Ms. Bellard considers Southwest's seasonal daily basic service charge increase is too high (60 percent increase) and would cause extreme customer confusion; therefore, she is only recommending a $1 increase (12.5 percent) to $9 per month in Northern Nevada and Southern Nevada. (Exhibit 78 at 9-10.)

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[20] Mr. Marcus believes all classes should be moved toward the system average rate of return, largely on a gradual basis. (Exhibit 75 at 31.)

Southwest's Rebuttal Position

300. Regarding BCP's argument that Southwest's rate design proposal creates very large increases for small users, Mr. Miller believes BCP's argument cannot be used as an excuse for failing to start the process of moving at least part way towards Southwest's rate design proposal. However, that said, Mr. Miller does not agree with Mr. Marcus' argument because he distorts the percentage increases on each customers' bill in his schedules (Exhibit 75 at 34[21]). Southwest's Schedule O-2, Sheets 1 & 2 show smaller percentage increases in rates than those increases presented by BCP when purchased gas costs are included. Therefore, Mr. Miller believes Southwest's rate design proposal is appropriate.

301. In further support of its proposed strategy, Southwest also presents Exhibit ABC-2, which shows that Southwest's intraclass subsidies, provided by large volume residential customers[22] to smaller volume customers, are significant. Southwest's proposed new basic service charges and declining block rates significantly reduce this intraclass subsidy by putting the costs in the first block. Southwest also points out that its proposed basic service charges are less than 100% of its customer-related charges (Statement O, Sheet 8, lines 3 and 6) and that its proposed winter differential is on-average less than the summer basic service charges due to greater usage in the winter (Exhibit 84 at 7, Lines 24-27.)

302. Regarding BCP's second argument that Southwest's proposed rate design would provide a reduction in risk, Southwest counters that this is not a reason to reject the proposal because there is nothing wrong with reducing Southwest's risk. (Exhibit 82 at 8.)

Commission Discussion and Findings

303. As stated above, the Commission believes in moving to cost based rates in principle and to the extent this reduces Southwest's risk, the Commission agrees with Southwest that there is nothing wrong with that outcome. However, the Commission also agrees with Staff's argument that to move more gradually toward that goal is more appropriate than moving

[21] Southwest disputes the validity of BCP's claims (Exhibit 84 at 11 & Exhibit ABC-3).
[22] Southwest's low-income and senior residential customers use relatively large volumes of gas and are providing a significant subsidy to Southwest's low use customers. (Exhibit ABC-2.)

as quickly as Southwest proposes. And even though BCP does not recommend changing the basic service charge in this proceeding, the Commission notes that Mr. Marcus also advocates gradualism.

304. The Commission believes that price movement based on gradualism should take into account two parallel situations. First, gas customers have experienced significant rate increases during the past three to four years due to a volatile gas market. In addition, Southwest has experienced rising investments/costs and declining margins due to rapid customer growth and declining average customer sales. Therefore, the Commission finds that a gradual increase in the basic service charge to $8.50 in the Northern and Southern divisions, based on the Commission's desire to balance the customer and company's parallel interests, is just and reasonable and approved.

305. Nevertheless, the Commission believes Southwest, Staff and BCP could have supplied more detailed information to support their basic service charge positions. Consequently, the Commission requests the parties in the future to support their proposed positions with more detailed information.

D. Seasonal Declining Block Rate Design

Southwest's Position

306. Southwest proposes two major rate design changes to address its problems to achieve revenue and income stability. The first is a package of changes to Southwest's rate schedules and the other change is the MCB (above). Besides the seasonal daily basic service charge, which was also discussed above, Southwest is proposing to extend the declining block rate structure to the winter months and to establish the first block volumes to capture approximately 50 percent of the respective summer and winter season volumes. According to Mr. Miller, the size of the first block would also reflect average usage in each season, so it would be a shorter block in summer than winter. Thus, by using declining blocks, Southwest could continue using commodity charges to recover a significant portion of its fixed costs, while

simultaneously reducing the variations in fixed cost revenue recovery that result from variations in usage volumes. (Exhibit 68 at 14-19 & Exhibit 74 at 23.)

BCP's Position

307. Mr. Marcus advises against adopting Southwest's declining block rate proposal because it encourages the consumption of gas contrary to public policy and reduces investments in energy efficient appliances. (Exhibit 75 at 34-36.)

308. Mr. Marcus recommends that the commodity rates in both Northern and Southern Nevada be increased only by equal cents per therm to collect the revenue requirement assigned to the residential class. (Id. at 41.)

Staff's Position

309. Ms. Bellard supports and agrees in part with Southwest's declining block rates. In the Southern division, she supports Southwest's 15 therms first block in the summer, which captures 58 percent of the usage. To capture the same 58 percent usage in the winter's first block, Ms. Bellard recommends using 45 therms instead of Southwest's 40 therms. (Exhibit 78 at 11.)

310. In the Northern division, Ms. Bellard also supports Southwest's 20 therms first block in the summer, which captures 56 percent of the usage. To capture the same 56 percent usage in the winter's first block, she recommends using 65 therms instead of Southwest's 55 therms. (Id. at 11.)

Southwest's Rebuttal Position

311. Mr. Miller explains that Mr. Marcus' argument that Southwest's declining block rates encourage consumption and lead to reduced investments in energy efficient appliances is misplaced and fundamentally incorrect. He points out that Southwest's proposed rate design, in fact, discourages consumption because it requires any customer to pay a higher gas bill if the customer uses more gas. (Exhibit 82 at 12.)

312. He also points out that the proper price to encourage an economic level of consumption and energy efficiency is the marginal or incremental costs of production. This

price provides the appropriate signal to customers in a free economy with customer choice, and the resulting choice will lead to an economically efficient use of resources. The concept of an economically efficient use of resources encompasses economically appropriate conservation of the economy's scare resources, and it also encompasses energy efficiency. Mr. Miller states that these concepts of competition, pricing and economic efficiency for energy conservation are highlighted in NAC 704.6671. (Id. at 12-13.)

313. He also states that Southwest's proposed rate design provides a much better reflection of Southwest's marginal cost of delivering gas volumes than Southwest's present rate design because the proposed lower tail-block rate design approximates Southwest's marginal price of delivering gas. (Id. at 16.)

Commission Discussion and Findings

314. The Commission recognizes that Southwest is experiencing problems achieving revenue and income stability due to declining average residential customer usage, and that Southwest's declining block rates are designed to help correct these problems. The Commission also believes that Staff's proposed minor modifications to capture Southwest's percent usage in both summer and winter periods are appropriate and encapsulate Southwest's same rate design, which recovers a significant portion of its fixed costs in the first block. Therefore, the Commission finds Staff's declining block rates contained in Paragraphs 309 and 310 above are just and reasonable and approved.

315. Regarding the declining block rates, the Commission directs Southwest to file a plan within six months on its efforts to educate its customers regarding conservation and any programs implemented to improve and promote efficiency.

VII. Weather Normalization

Staff's Position

316. Staff recommends that the Commission accept Southwest's weather normalization adjustments as filed, because no significant differences exist between Staff and Southwest. However, Staff recommends that the Commission order Southwest to address concerns regarding

model validity as measured by statistical tests for homoskedasticity (a sequence of random variables having the same finite variance) and normality of distribution of error terms by requiring Southwest to include the results of such tests in all future filings in which the issue of weather normalization is addressed. (Staff Brief at 15.)

Commission Discussion and Findings

317. Southwest's weather normalization adjustments are not an issue in this case other than Staff's request that Southwest should include the results of its statistical test. Therefore, the Commission finds that Southwest's weather normalization adjustments are accepted in this case. The Commission orders Southwest to include the results of its statistical test for homoskedasticity and normality of distribution of error terms in all future filings in which the issue of weather normalization is addressed. The Commission also orders Southwest Gas Corporation to file in its next general rate case a weather normalization plan to address its revenue volatility issues.

VIII. Commission Overall Findings and Conclusions

318. In light of the findings and conclusions contained in this Order, the increase to Southwest's annual revenue requirement for the Northern Division is $6,371,720 and $7,346,359 for the Southern Division. A summary of the adjustments contained in this Order is attached as "Attachment 3".

319. The Commission finds that Southwest shall implement the Commission findings in this Order, develop appropriate rates, and submit appropriate documentation, and draft tariff sheets to Staff for review prior to placing the rates into effect.

320. The Commission also finds that, once the tariffs have been verified by Staff, Southwest shall place the rates into effect on September 1, 2004.

THEREFORE, based on the foregoing findings and conclusions, it is hereby ORDERED that:

1. The Application filed by Southwest Gas Corporation and designated as 04-3011 is APPROVED in accordance with the findings and conclusions in this Order.

2. Pursuant to paragraph 195, Southwest Gas Corporation shall file a plan to address the imbalance in seasonal natural gas usage within six months of the issuance of this Order.

3. Southwest Gas Corporation shall determine the requirements to adequately identify the factors and forces of retirement for Account 376: Mains and Account 380: Services for the Northern and Southern Divisions and submit its findings to the Commission within six months from the issuance date of this Order.

4. Pursuant to paragraph 315, Southwest Gas Corporation shall file a plan within six months of the issuance of this Order concerning its efforts to educate its customers regarding conservation and any programs implemented to improve and promote efficiency.

5. Southwest Gas Corporation shall include the results of its statistical test as discussed in paragraph 317 in its next general rate case.

6. Pursuant to paragraph 317, Southwest Gas Corporation shall file in its next general rate case a weather normalization plan to address its revenue volatility issues.

7. The Commission retains jurisdiction for the purpose of correcting any errors which may have occurred in the drafting or issuance of this Order.

By the Commission,

DONALD L. SODERBERG, Chairman

ADRIANA ESCOBAR CHANOS, Commissioner and Presiding Officer (dissenting as to paragraphs 194, 195, and 196)

CARL B. LINVILL, Commissioner

Attest: Acting
for CRYSTAL JACKSON, Commission Secretary

Dated: Carson City, Nevada

(SEAL) 8/30/04

PUBLIC UTILITIES COMMISSION PUC OF NEVADA

ATTACHMENT 1

Southwest Gas Corporation
Southern Nevada

Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation
Rates and Depreciation Expense Based Upon Utilization of Book Depreciation Reserve
and Average Remaining Lives of Utility Plant in Service as of December 31, 2002

Acct. No. (a)	Account Description (b)	Original Cost 12-31-2002 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)=(c)x(d)	Original Cost Less Salvage (f)=(c)-(e)	Book Depreciation Reserve (g)	Net Original Cost Less Book Reserve (h)=(f)-(g)	A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)=(h)/(j)	Annual Depreciation Rate (l)=((k)/(c))*100
	DEPRECIABLE PLANT										
	Transmission Plant										
365.20	Rights of Way	107,068	0%	0	107,068	67,476	39,592	75-R4	44.2	896	0.84%
366.10	Structures - Compressor Stations	647,857	-5%	-32,393	680,250	292,110	388,140	45-R3	25.4	15,281	2.36%
366.20	Structures - General	189,102	-5%	-9,455	198,557	39,151	159,406	45-R3	35.4	4,503	2.38%
367.00	Transmission Mains	68,764,996	-5%	-3,438,250	72,203,246	17,692,245	54,511,001	50-R3	37.5	1,453,627	2.11%
368.00	Compressor Station Equipment	4,632,278	-1%	-46,323	4,678,601	2,286,166	2,392,435	29-R3	13.6	175,914	3.80%
369.00	Meas/Reg Station Equipment	10,009,965	-5%	-500,498	10,510,463	2,302,154	8,208,309	40-R3	32.6	251,789	2.52%
370.00	Communication Equipment	210,915	0%	0	210,915	139,691	71,224	17-R4	8.0	8,903	4.22%
371.00	Miscellaneous Equipment	18,823	0%	0	18,823	11,513	7,310	10-R4	4.0	1,828	9.71%
	TOTAL Transmission Plant	84,581,004	-4.8%	-4,026,919	88,607,923	22,830,506	65,777,417			1,912,741	2.26%
	Distribution Plant										
374.20	Rights of Way	236,527	0%	0	236,527	89,826	146,701	75-R4	44.2	3,319	1.40%
375.00	Structures	1,959	0%	0	1,959	1,801	158	45-R3	10.2	15	0.77%
376.00	Distribution Mains	308,215,502	-10%	-30,821,550	339,037,052	54,334,125	284,702,927	43-R2	35.6	8,007,186	2.60%
378.00	Meas/Reg Station Equipment	8,588,167	-25%	-2,147,042	10,735,209	2,039,893	8,695,316	25-R2.5	18.5	470,017	5.47%
380.00	Services	222,831,749	-12%	-26,739,810	249,571,559	60,983,361	188,588,198	41-R3	32.8	5,754,958	2.58%
381.00	Meters	75,178,092	-3%	-2,255,343	77,433,435	19,242,124	58,191,311	33-R3	24.4	2,446,511	3.25%
385.00	Industrial Meas/Reg Station Equip.	3,537,095	-30%	-1,061,129	4,598,224	754,802	3,843,422	32-R3	25.3	151,914	4.29%
387.00	Miscellaneous Equipment	-3,743	0%	0	-3,743	-4,455	712	16-R3	3.0	237	*
	TOTAL Distribution Plant	618,585,348	-10.2%	-63,024,874	681,610,222	137,441,477	544,168,745			16,834,157	2.72%
	General Plant										
390.10	Structures - Owned	11,636,570	5%	581,829	11,054,741	1,637,137	9,417,604	40-R3	28.1	335,146	2.88%
391.00	Office Furniture & Equipment	1,523,048	0%	0	1,523,048	123,960	1,399,088	18-R0.5	12.0	116,591	7.66%
391.10	Computer Equipment	2,646,203	0%	0	2,646,203	-1,097,800	3,744,003	5-L2	3.4	1,101,177	41.61%
	Total Account 391	4,169,251	0.0%	0	4,169,251	-973,840	5,143,091			1,217,768	29.21%
392.11	Transportation Equipment - Light	6,878,008	10%	687,801	6,190,207	2,760,189	3,430,018	7-R3	4.4	779,550	11.33%
392.12	Transportation Equipment - Heavy	2,984,844	7%	208,939	2,775,905	439,064	2,336,841	11-R3	7.8	299,595	10.04%
	Total Account 392	9,862,852	9.1%	896,740	8,966,112	3,199,253	5,766,859			1,079,145	10.94%

393.00	Stores Equipment	386,081	0%	0	386,081	130,585	255,496	24-L3	10.2	25,049	6.49%
394.00	Tools, Shop & Garage Equipment	2,110,895	0%	0	2,110,895	-424,363	2,535,258	15-L0.5	10.7	236,940	11.22%
395.00	Laboratory Equipment	107,351	0%	0	107,351	21,524	85,827	17-L2	11.0	7,802	7.27%
396.00	Power Operated Equipment	959,455	15%	143,918	815,537	219,019	596,518	13-L0.5	9.1	65,551	6.83%
397.00	Communication Equipment	813,091	0%	0	813,091	-118,461	931,552	14-L1.5	9.0	103,506	12.73%
397.20	Telemetry Equipment	124,603	0%	0	124,603	141,090	-16,487	8-R3	1.6	-10,304	-8.27%
	Total Account 397	937,694	0.0%	0	937,694	22,629	915,065			93,202	9.94%
398.00	Miscellaneous Equipment	137,432	0%	0	137,432	-73,310	210,742	15-L0	11.8	17,859	12.99%
	TOTAL General Plant	30,307,581	5.4%	1,622,487	28,685,094	3,758,634	24,926,460			3,078,462	10.16%
	TOTAL Depreciable Plant	733,473,933	-8.9%	-65,429,306	798,903,239	164,030,617	634,872,622			21,825,360	2.98%

Southwest Gas Corporation

Northern Nevada

Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation
Rates and Depreciation Expense Based Upon Utilization of Book Depreciation Reserve
and Average Remaining Lives of Utility Plant in Service as of December 31, 2002

Acct. No. (a)	Account Description (b)	Original Cost 12-31-2002 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)=(c)x(d)	Original Cost Less Salvage (f)=(c)-(e)	Book Depreciation Reserve (g)	Net Original Cost Less Book Reserve (h)=(f)-(g)	A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)=(h)/(j)	Annual Depreciation Rate (l)=((k)/(c))*100
	DEPRECIABLE PLANT										
	Distribution Plant										
374.20	Rights of Way	1,203	0%	0	1,203	437	766	75-R4	46.8	16	1.33%
376.00	Distribution Mains	64,532,184	-11%	-7,098,540	71,630,724	14,905,609	56,725,115	38-R3	28.1	2,017,014	3.13%
378.00	Meas/Reg Station Equipment	1,094,727	-15%	-164,209	1,258,936	445,738	813,198	28-R2	19.4	41,917	3.83%
380.00	Services	52,573,319	-35%	-18,400,662	70,973,981	13,042,114	57,931,867	32-R3	22.5	2,574,154	4.90%
381.00	Meters	17,562,701	-3%	-526,881	18,089,582	5,287,077	12,802,505	35-L1.5	26.1	490,517	2.79%
385.00	Industrial Meas/Reg Station Equip.	969,772	-20%	-193,954	1,163,726	260,279	903,447	30-R2	21.0	43,021	4.44%
387.00	Miscellaneous Equipment	7,065	0%	0	7,065	2,199	4,866	23-R3	17.1	285	4.03%
	TOTAL Distribution Plant	136,740,971	-19.3%	-26,384,246	163,125,217	33,943,453	129,181,764			5,166,924	3.78%
	General Plant										
390.10	Structures - Owned	5,488,167	5%	274,408	5,213,759	656,483	4,557,276	40-R3	30.9	147,485	2.69%
391.00	Office Furniture & Equipment	528,241	0%	0	528,241	-147,169	675,410	16-S0.5	9.4	71,852	13.60%
391.10	Computer Equipment	872,031	0%	0	872,031	-291,489	1,163,520	5-L2	3.1	375,329	43.04%
	Total Account 391	1,400,272	0.0%	0	1,400,272	-438,658	1,838,930			447,181	31.94%
392.11	Transportation Equipment - Light	2,211,838	5%	110,592	2,101,246	966,231	1,135,015	7-R3	3.7	306,761	13.87%
392.12	Transportation Equipment - Heavy	1,092,770	0%	0	1,092,770	273,182	819,588	15-L2	11.1	73,837	6.76%
	Total Account 392	3,304,608	3.3%	110,592	3,194,016	1,239,413	1,954,603			380,598	11.52%
393.00	Stores Equipment	131,869	0%	0	131,869	-22,266	154,135	20-R0.5	14.6	10,557	8.01%
394.00	Tools, Shop & Garage Equipment	786,051	0%	0	786,051	-3,216	789,267	20-L1	14.3	55,193	7.02%
395.00	Laboratory Equipment	79,219	0%	0	79,219	-1,960	81,179	18-L2	13.5	6,013	7.59%
396.00	Power Operated Equipment	779,112	25%	194,778	584,334	98,872	485,462	14-R1	9.1	53,347	6.85%
397.00	Communication Equipment	931,308	0%	0	931,308	-179,918	1,111,226	10-L1	7.4	150,166	16.12%
	Total Account 397	931,308	0.0%	0	931,308	-179,918	1,111,226			150,166	16.12%
398.00	Miscellaneous Equipment	35,058	0%	0	35,058	-102,328	137,386	10-L0	5.8	23,687	67.57%
	TOTAL General Plant	12,935,664	4.5%	579,778	12,355,886	1,246,422	11,109,464			1,274,227	9.85%
	TOTAL Depreciable Plant	149,676,635	-17.2%	-25,804,468	175,481,103	35,189,875	140,291,228			6,441,151	4.30%

ATTACHMENT 2

Docket No. 04-3011
Schedule____

Public Utilities Commission
Southwest Gas Corporation
Test Period Ending September 30, 2003
Annualized Depreciation Expense Detail
Southern Nevada Division

Line No.	Acct No.	Description	SWG Recorded Plant at Sept 2003	Comm. Deprec. Rates	Comm Annual Depreciation Expense	SWG Annual Expense	Commission Depreciation Adjustment	Line No.
			(a)	(b)	(c)	(d)	(e)	
		INTANGIBLE						
1	301.0	Organization	$68,482	0.00%	0	0	0	1
2	302.0	Franchise & Consent	0	0.00%	0	0	0	2
3	303.0	Misc. Intangible	879,072	33.33%	292,995	292,995	0	3
4		Total Intangible	947,554		292,995	292,995	0	4
		PRODUCTION						
5	325.5	Other Land & Land Rights	21,712	N/A	0	0	0	5
6	332.0	Field Lines	265,726	0.00%	0	0	0	6
7	334.0	Field Meas. & Reg. Sta.	111,942	2.38%	2,664	2,664	0	7
8	336.0	Purification Equipment	14,707	0.00%	0	0	0	8
9		Total Production	414,087		2,664	2,664	0	9
		TRANSMISSION						
10	365.1	Land & Land Rights	436,334	N/A	0	0	0	10
11	365.2	Rights of Way	107,068	0.84%	899	899	0	11
12	366.1	Structures - Compressor Stations	647,857	2.36%	15,289	15,289	0	12
13	366.2	Structures - General	189,102	2.38%	4,501	4,501	0	13
14	367.0	Transmission Mains	75,485,996	2.11%	1,592,755	1,698,435	(105,680)	14
15	367.2	Mains - Bridge	105,956	0.00%	-	0	0	15
16	368.0	Compressor Sta.	4,693,344	3.80%	178,347	178,347	0	16
17	369.0	Meas. & Reg. Sta. Eq.	8,527,781	2.52%	214,900	227,692	(12,792)	17
18	370.0	Communication Eq.	210,915	4.22%	8,901	8,901	0	18
19	371.0	Other Equipmment	18,823	9.71%	1,828	1,828	0	19
20		Total Transmission	90,423,176		2,017,419	2,135,892	(118,472)	20
		DISTRIBUTION						
13	374.1	Land & Land Rights	0	N/A	0	0		13
14	374.2	Rights of Way	236,527	1.40%	3,311	3311		14
15	375.0	Structures	1,959	0.77%	15	15	0	15
16	376.0	Distribution Mains	335,659,309	2.60%	8,727,142	9,868,384	(1,141,242)	16
17	378.0	Meas. & Reg. Sta. Eq.	9,054,146	5.47%	495,262	519,708	(24,446)	17
18	380.0	Services	238,930,786	2.58%	6,164,414	7,860,823	(1,696,409)	18
19	381.0	Meters	81,091,195	3.25%	2,635,464	2,635,464	(0)	19
20	385.0	Industrial Meas. & Reg. Sta. Eq.	3,662,628	4.29%	157,127	157,127	0	20
21	386.0	Other Prop. - Cust. Prem.	0	N/A	0	0	0	21
22	387.0	Other Eq.	(3,743)	0.00%	0	0	0	22
23		Total Distribution	668,632,807		18,182,735	21,044,832	(2,862,097)	23

Public Utilities Commission
Southwest Gas Corporation
Test Period Ending September 30, 2003
Annualized Depreciation Expense Detail
Southern Nevada Division

Docket No. 04-3011
Schedule____

Line No	Acct No.	Description	SWG Recorded Plant at Sept 2003	Comm. Deprec. Rates	Comm Annual Depreciation Expense	SWG Annual Expense	Commission Depreciation Adjustment	Line No.
			(a)	(b)	(c)	(d)	(e)	
		GENERAL PLANT						
24	389.0	Land & Land Rights	3,767,698	0.00%	0	0	0	24
25	390.1	Structures & Improvements	11,659,539	2.88%	335,795	335,795	0	25
26	390.2	Structures & Improvements - Lease	186,859	20.00%	37,372	37,372	0	26
27	391.0	Office Furniture & Equipment	1,530,678	7.66%	117,250	117,250	0	27
28	391.1	Computer Equipment	3,009,468	41.61%	1,252,240	1,252,240	0	28
29	392.11	Trans. Eq. - Light	7,124,240	11.33%	641,110	641,110	0	29
30	392.12	Trans. Eq. - Heavy	2,986,417	10.04%	238,149	238,149	0	30
31	393.0	Stores Equipment	386,081	6.49%	25,057	25,057	0	31
32	394.0	Tools, Shop & Garage Equipment	2,209,647	11.22%	247,922	247,922	0	32
33	395.0	Laboratory Equipment	117,280	7.27%	8,526	8,526	0	33
34	396.0	Power Operated Equipment	971,358	6.83%	52,694	52,694	0	34
35	397.1	Communication Equipment	813,091	12.73%	103,506	103,506	0	35
36	397.2	Telemetering Equipment	124,603	-8.27%	(10,305)	(10,305)	0	36
37	398.0	Miscellaneous Equipment	140,107	12.99%	18,200	18,200	0	37
38		Total General Plant	35,027,066		3,067,516	3,067,516	0	38
39		Total	795,444,690		23,563,330	26,543,899	(2,980,569)	39

Numbers for columns (a) and (d) were obtained from SWG's Schedule H-26, Sheet 1 of 2, columns (c) and (g), respectively.

D- 04-3011
Schedule ____

Southwest Gas Corporation
Northern Nevada Division
Annualized Depreciation Expense Detail
Test Period Ending September 30, 2003

Line No.	Acct No.	Description	SWG Recorded Plant at Sept 2003	Comm. Deprec. Rates	Comm. Annual Depreciation Expense	SWG Annual Expense	Commission Depreciation Adjustment	Line No.
			(a)	(b)	(c)	(d)	(e)	
		INTANGIBLE						
1	301.0	Organization	0		0	0	0	1
2	302.0	Franchise & Consent	61,157	3.25%	1,988	1,987	0	2
3	303.0	Misc. Intangible	28,635	0.00%	0	0	0	3
4		Total Intangible	89,792		1,988	1,987	0	4
		DISTRIBUTION						
5	374.1	Land & Land Rights	962	N/A	0	0	0	5
6	374.2	Rights of Way	1,203	1.33%	16	16	0	6
7	376.0	Distribution Mains	67,341,855	3.13%	2,107,800	2,397,370	(289,570)	7
8	378.0	Meas. & Reg. Sta. Eq.	1,094,727	3.83%	41,928	41,928	0	8
9	380.0	Services	55,672,342	4.90%	2,727,945	2,894,962	(167,017)	9
10	381.0	Meters	17,663,488	2.79%	492,811	540,503	(47,692)	10
11	385.0	Industrial Meas. & Reg. Sta. Eq.	996,103	4.44%	44,227	44,227	0	11
12	387.0	Other Eq.	9,726	4.03%	392	392	0	12
13		Total Distribution	142,780,406		5,415,119	5,919,398	(504,279)	13
		GENERAL PLANT						
14	389.0	Land & Land Rights	2,202,619	0.00%	0	0	0	14
15	390.1	Structures & Improvements	5,488,167	2.69%	147,632	147,632	0	15
16	390.2	Structures & Improvements - Lease	101,166	Various	2,358	2,358	0	16
17	391.0	Office Furniture & Equipment	589,087	13.60%	80,116	80,116	0	17
18	391.1	Computer Equipment	918,216	43.04%	395,200	395,200	0	18
19	392.11	Trans. Eq. - Light	2,123,209	13.87%	241,481	217,977	23,504	19
20	392.12	Trans. Eq. - Heavy	1,094,033	6.76%	60,644	56,607	4,037	20
21	393.0	Stores Equipment	131,869	8.01%	10,563	10,563	0	21
22	394.0	Tools, Shop & Garage Equipment	810,637	7.02%	56,907	56,907	0	22
23	395.0	Laboratory Equipment	79,219	7.59%	6,013	6,013	0	23
24	396.0	Power Operated Equipment	786,402	6.85%	44,172	44,172	0	24
25	397.1	Communication Equipment	931,308	16.12%	150,127	150,127	0	25
26	398.0	Miscellaneous Equipment	35,058	67.57%	23,689	23,689	0	26
27		Total General Plant	15,290,990		1,218,901	1,191,361	27,540	27
28		Total	158,161,188		6,636,008	7,112,746	(476,739)	28

Numbers for columns (a) and (d) were obtained from SWG's Schedule H-26, Sheet 1 of 2, columns (c) and (g), respectively.

ATTACHMENT 3

PUBLIC UTILITIES COMMISSION OF NEVADA
SOUTHWEST GAS CORPORATION
SOUTHERN NEVADA
TEST YEAR ENDED 9/30/03
SUMMARY OF OPERATIONS AND RATE BASE

Line No.	Description	Applicant Adjusted Amounts #REF!	Commission Adjustments	Commission Adjusted	Deficiency	Total Revenue Requirement
	(a)	(b)	(c)	(d)	(e)	(f)
		Stmt. H, Pg. 1, Col (e)	Pg. 4, Col (s)	(=B+C)	Pg. 7-9	(=D+E)
1	Operating Revenue	$138,295,899	$0	$138,295,899	$7,346,359	$145,642,258
1a	Other Revenue	0	831,183	831,183	0	831,183
2	Gas Cost	0	0	0	0	0
3	Operating Margin	$138,295,899	$831,183	$139,127,082	$7,346,359	$146,473,441
	Operating Expenses					
4	Other Gas Costs	$228,066	$0	$228,066	$0	$228,066
5	Transmission	1,648,946	0	1,648,946	0	1,648,946
6	Distribution	26,543,435	0	26,543,435	0	26,543,435
7	Customer Accounts	15,955,176	3,168	15,958,344	26,919	15,985,263
8	Customer Service & Information	268,253	0	268,253	0	268,253
9	Sales	0	0	0	0	0
	Administrative and General					
10	Southern Nevada Division	1,447,408	(784,180)	663,228	0	663,228
11	System Allocable	15,864,216	(24,358)	15,839,858	0	15,839,858
	Depreciation and Amortization					
12	Southern Nevada Division	26,648,595	(3,066,936)	23,581,659	0	23,581,659
13	System Allocable	3,372,355	(791,666)	2,580,689	0	2,580,689
14	Taxes Other Than Income	2,991,731	0	2,991,731	0	2,991,731
	Regulatory Amortization	251,299	(231,000)	20,299	0	20,299
16	Subtotal Expenses	$95,219,481	($4,894,972)	$90,324,509	$26,919	$90,351,428
17	Net Operating Income before FIT	$43,076,418	$5,726,155	$48,802,573	$7,319,440	$56,122,013
18	Federal Income Taxes	8,818,258	1,703,199	10,521,457	2,561,780	13,083,237
19	Regulatory Amortization	0	0	0	0	0
20	Ratemaking Amortization - CP National	254,510	0	254,510	0	254,510
21	Total Other Expenses	$9,072,768	$1,703,199	$10,775,967	$2,561,780	$13,337,747
22	Net Operating Income	$34,003,650	$4,022,956	$38,026,606	$4,757,660	$42,784,266
	Rate Base					
	Gas Plant in Service					
23	Southern Nevada Division	$797,319,220	($1,251,049)	$796,068,171		$796,068,171
24	System Allocable	39,351,534	(7,694,556)	31,656,978		31,656,978
25	Total Gross Plant	$836,670,754	($8,945,605)	$827,725,149		$827,725,149
	Accumulated Provision for Depreciation and Amortization					
26	Southern Nevada Division	$180,048,085	$0	$180,048,085		$180,048,085
27	System Allocable	19,511,474	(189,735)	19,321,739		19,321,739
28	Total Accumulated Provision for Depreciation and Amortization	$199,559,560	($189,735)	$199,369,825		$199,369,825
29	Net Plant in Service	$637,111,194	($8,755,870)	$628,355,324		$628,355,324
	Other Rate Base Items					
30	Materials and Supplies	5,087,165	0	5,087,165		5,087,165
31	Working Capital	5,776,130	(3,874,208)	1,901,923		1,901,923
32	Customer Advances	(4,657,361)	0	(4,657,361)		(4,657,361)
33	Deferred Taxes	(67,458,198)	11,056,603	(56,401,595)		(56,401,595)
34	Total Other Rate Base Items	($61,252,264)	$7,182,395	($54,069,869)		($54,069,869)
35	Total Rate Base	$575,858,930	($1,573,475)	$574,285,455		$574,285,455
	Rate of Return	5.90%		6.62%		7.45%

PUBLIC UTILITIES COMMISSION OF NEVADA
SOUTHWEST GAS CORPORATION
SOUTHERN NEVADA
TEST YEAR ENDED 9/30/03
SUMMARY OF COMMISSION ADJUSTMENTS

Line No.	Description	WMS Adj. No. 1	CCNC Adj. No. 2	Land Sale Adj. No. 3	SERP & EDCP Expense Adj. No. 4	Working Cash Adj. No. 5	Service Establishment Revenues Adj. No. 6	Late Charge Revenues Adj. No. 7
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Operating Revenue	$0	$0	$0	$0	$0	$0	$0
1a	Other Revenue	0	0	69,183	0	0	113,000	649,000
2	Gas Cost	0	0	0	0	0	0	0
3	Operating Margin	$0	$0	$69,183	$0	$0	$113,000	$649,000
	Operating Expenses							
4	Other Gas Costs	$0	$0	$0	$0	$0	$0	$0
5	Transmission	0	0	0	0	0	0	0
6	Distribution	0	0	0	0	0	0	0
7	Customer Accounts	0	0	0	0	0	0	0
8	Customer Service & Information	0	0	0	0	0	0	0
9	Sales	0	0	0	0	0	0	0
	Administrative and General							
10	Southern Nevada Division	0	0	0	(759,000)	0	0	0
11	System Allocable	0	0	0	(237,000)	0	0	0
	Depreciation and Amortization							
12	Southern Nevada Division	0	(86,367)	0	0	0	0	0
13	System Allocable	(758,970)	(32,696)	0	0	0	0	0
14	Taxes Other Than Income	0	0	0	0	0	0	0
15	Regulatory Amortization	0	0	0	0	0	0	0
16	Subtotal Expenses	($758,970)	($119,063)	$0	($996,000)	$0	$0	$0
17	Net Operating Income before FIT	$758,970	$119,063	$69,183	$996,000	$0	$113,000	$649,000
18	Federal Income Taxes	265,640	41,672	24,214	348,600	0	39,550	227,150
19	Regulatory Amortization	0	0	0	0	0	0	0
20	Ratemaking Amortization	0	0	0	0	0	0	0
21	Total Other Expenses	$265,640	$41,672	$24,214	$348,600	$0	$39,550	$227,150
22	Net Operating Income	$493,330	$77,391	$44,969	$647,400	$0	$73,450	$421,850
	Rate Base							
	Gas Plant in Service							
23	Southern Nevada Division	$0	($1,251,049)	$0	$0	$0	$0	$0
24	System Allocable	(7,589,695)	(104,861)	0	0	0	0	0
25	Total Gross Plant	($7,589,695)	($1,355,910)	$0	$0	$0	$0	$0
	Accumulated Provision for Depreciation and Amortization							
26	Southern Nevada Division	$0	$0	$0	$0	$0	$0	$0
27	System Allocable	(189,735)	0	0	0	0	0	0
28	Total Accumulated Provision for Depreciation and Amortization	($189,735)	$0	$0	$0	$0	$0	$0
29	Net Plant in Service	($7,399,960)	($1,355,910)	$0	$0	$0	$0	$0
	Other Rate Base Items							
30	Materials and Supplies	$0	$0	$0	$0	$0	$0	$0
31	Working Capital	0	0	0	1,523,000	(138,304)	0	0
32	Customer Advances	0	0	0	0	0	0	0
33	Deferred Taxes	1,535,967	0	0	0	0	0	0
34	Total Other Rate Base Items	$1,535,967	$0	$0	$1,523,000	($138,304)	$0	$0
35	Total Rate Base	($5,863,993)	($1,355,910)	$0	$1,523,000	($138,304)	$0	$0
	Order Paragraph / Attachment	106	114	117	132	150	153	157
	Exhibit	38	38	38	44	36	44	44
		Attch. KJP-2	Attch. KJP-3	Attch. KJP-5	Attch. B-2, C-2.2	Attch. DJG-10	Attch. C-1.1	Attch. C-1.1

PUBLIC UTILITIES COMMISSION OF NEVADA
SOUTHWEST GAS CORPORATION
SOUTHERN NEVADA
TEST YEAR ENDED 9/30/03
SUMMARY OF COMMISSION ADJUSTMENTS

Line No.	Description	Medical Insurance Adj. No. 8	Corporate Labor Adj. No. 9	DSM Amortization Adj. No. 10	Aircraft Liability Ins. Adj. No. 11	ADIT for NOL Adj. No. 12	AMT Prepraid Adj. No. 13	Annualized Depreciation Expense Adj. No. 14
	(a)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	Operating Revenue	$0	$0	$0	$0	$0	$0	$0
1a	Other Revenue	0	0	0	0	0	0	0
2	Gas Cost	0	0	0	0	0	0	0
3	Operating Margin	$0	$0	$0	$0	$0	$0	$0
	Operating Expenses							
4	Other Gas Costs	$0	$0	$0	$0	$0	$0	$0
5	Transmission	0	0	0	0	0	0	0
6	Distribution	0	0	0	0	0	0	0
7	Customer Accounts	0	0	0	0	0	0	0
8	Customer Service & Information	0	0	0	0	0	0	0
9	Sales	0	0	0	0	0	0	0
	Administrative and General							
10	Southern Nevada Division	(25,180)	0	0	0	0	0	0
11	System Allocable	(8,820)	221,983	0	(521)	0	0	0
	Depreciation and Amortization							
12	Southern Nevada Division	0	0	0	0	0	0	(2,980,569)
13	System Allocable	0	0	0	0	0	0	0
14	Taxes Other Than Income	0	0	0	0	0	0	0
15	Regulatory Amortization	0	0	(231,000)	0	0	0	0
16	Subtotal Expenses	($34,000)	$221,983	($231,000)	($521)	$0	$0	($2,980,569)
17	Net Operating Income before FIT	$34,000	($221,983)	$231,000	$521	$0	$0	$2,980,569
18	Federal Income Taxes	11,900	(77,694)	80,850	182	0	0	1,043,199
19	Regulatory Amortization	0	0	0	0	0	0	0
20	Ratemaking Amortization	0	0	0	0	0	0	0
21	Total Other Expenses	$11,900	($77,694)	$80,850	$182	$0	$0	$1,043,199
22	Net Operating Income	$22,100	($144,289)	$150,150	$339	$0	$0	$1,937,370
	Rate Base							
	Gas Plant in Service							
23	Southern Nevada Division	$0	$0	$0	$0	$0	$0	$0
24	System Allocable	0	0	0	0	0	0	0
25	Total Gross Plant	$0	$0	$0	$0	$0	$0	$0
	Accumulated Provision for Depreciation and Amortization							
26	Southern Nevada Division	$0	$0	$0	$0	$0	$0	$0
27	System Allocable	0	0	0	0	0	0	0
28	Total Accumulated Provision for Depreciation and Amortization	$0	$0	$0	$0	$0	$0	$0
29	Net Plant in Service	$0	$0	$0	$0	$0	$0	$0
	Other Rate Base Items							
30	Materials and Supplies	$0	$0	$0	$0	$0	$0	$0
31	Working Capital	0	0	0	0	0	2,135,165	0
32	Customer Advances	0	0	0	0	0	0	0
33	Deferred Taxes	0	0	0	0	9,520,636	0	0
34	Total Other Rate Base Items	$0	$0	$0	$0	$9,520,636	$2,135,165	$0
35	Total Rate Base	$0	$0	$0	$0	$9,520,636	$2,135,165	$0
	Order Paragraph / Attachment	171	172	176	184	199	203	Attch. 2
	Exhibit	47 Attch. RLA-7	3 & 47	44 Attch. C-4	47	37 Attch. RAB-2	37 Attch. RAB-6	N/A

PUBLIC UTILITIES COMMISSION OF NEVA
SOUTHWEST GAS CORPORATION
SOUTHERN NEVADA
TEST YEAR ENDED 9/30/03
SUMMARY OF COMMISSION ADJUSTMEN

Line No.	Description (a)	Lead / Lag Study Adj. No. 15 (p)	Tax Exp - Int Synch Adj. No. 16 (q)	Uncollectible Expense Adj. No. 17 (r)	Total of Adjustments (s)
	Operating Revenue	$0	$0	$0	$0
1a	Other Revenue	0	0	0	831,183
2	Gas Cost	0	0	0	0
3	Operating Margin	$0	$0	$0	$831,183
	Operating Expenses				
4	Other Gas Costs	$0	$0	$0	$0
5	Transmission	0	0	0	0
6	Distribution	0	0	0	0
7	Customer Accounts	0	0	3,168	3,168
8	Customer Service & Information	0	0	0	0
9	Sales	0	0	0	0
	Administrative and General				
10	Southern Nevada Division	0	0	0	(784,180)
11	System Allocable	0	0	0	(24,358)
	Depreciation and Amortization				
12	Southern Nevada Division	0	0	0	(3,066,936)
13	System Allocable	0	0	0	(791,666)
14	Taxes Other Than Income	0	0	0	0
15	Regulatory Amortization	0	0	0	(231,000)
16	Subtotal Expenses	$0	$0	$3,168	($4,894,972)
17	Net Operating Income before FIT	$0	$0	($3,168)	$5,726,155
18	Federal Income Taxes	0	(300,955)	(1,109)	1,703,199
19	Regulatory Amortization	0	0	0	0
20	Ratemaking Amortization	0	0	0	0
21	Total Other Expenses	$0	($300,955)	($1,109)	$1,703,199
22	Net Operating Income	$0	$300,955	($2,059)	$4,022,956
	Rate Base				
	Gas Plant in Service				
23	Southern Nevada Division	$0	$0	$0	($1,251,049)
24	System Allocable	0	0	0	(7,694,556)
25	Total Gross Plant	$0	$0	$0	($8,945,605)
	Accumulated Provision for Depreciation and Amortization				
26	Southern Nevada Division	$0	$0	$0	$0
27	System Allocable	0	0	0	(189,735)
28	Total Accumulated Provision for Depreciation and Amortization	$0	$0	$0	($189,735)
29	Net Plant in Service	$0	$0	$0	($8,755,870)
	Other Rate Base Items				
30	Materials and Supplies	$0	$0	$0	$0
31	Working Capital	(7,394,069)	0	0	(3,874,208)
32	Customer Advances	0	0	0	0
33	Deferred Taxes	0	0	0	11,056,603
34	Total Other Rate Base Items	($7,394,069)	$0	$0	$7,182,395
35	Total Rate Base	($7,394,069)	$0	$0	($1,573,475)
	Order Paragraph / Attachment	Attch. 3, Pg. 5	Attch. 3, Pg. 8	Attch. 3, Pg. 9	
	Exhibit	N/A	N/A	N/A	

PUBLIC UTILITIES COMMISSION OF NEVADA
SOUTHWEST GAS CORPORATION
SOUTHERN NEVADA
TEST YEAR ENDED 9/30/03
SUMMARY OF CASH WORKING CAPITAL

Ln.	Description	Refer.	As Filed SWG Cost	Commission Adjustment	Adjusted Total Cost	Adjusted Lag Days	Dollar Days
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	Cost of Gas		$95,857,059		$95,857,059	42.62	$4,085,427,855
2	Labor and Benefits		37,748,656		37,748,656	10.69	403,533,133
3	Pension Costs Charged to O&M		1,916,752		1,916,752	0.00	0
4	Supplemental Retirement Plan Expense		1,018,562		1,018,562	0.00	0
5	Prepayments Amortized to O&M		1,534,891		1,534,891	0.00	0
6	Uncollectible Accounts Expense		1,160,613		1,160,613	189.52	219,959,376
7	Prepaid Insurance Amortized to O&M		1,452,328		1,452,328	0.00	0
8	Building Lease Charged to O&M		489,878		489,878	0.00	0
9	Other O&M Expenses		16,493,108		16,493,108	33.97	560,270,879
10	Total O&M Expenses		157,671,847	0	157,671,847	33.42	5,269,191,242
11	Depreciation and Amortization	a	30,020,855	(30,020,855)	0	0.00	0
12	Taxes Other Than Income Taxes		2,991,731		2,991,731	26.64	79,699,714
13	Federal Income Taxes - Current		1,971,114		1,971,114	39.00	76,873,446
14	Deferred Income Taxes	a	13,498,561	(13,498,561)	0	0.00	0
15	Equity Return	a	28,806,386	(28,806,386)	0	0.00	0
16	Interest Expense	a,b	17,882,308	(64,196)	17,818,112	73.49	1,309,453,051
17	Total Revenue Requirement		252,842,802	(72,389,998)	180,452,804	37.32	6,735,217,452
18	No. Of Days in Test Period		365	365	365		
19	Avg. Daily Revenue Requirement [L17/L18]		692,720	(198,329)	494,391		
20	Lag in Receipt of Revenue					36.80	
21	Net Rev Lag (Exp Lead) [Lag Days, L20-L17]		10.30		(0.52)		
22	Cash Working Capital for Operating Expense [L19xL21]		7,135,016	(7,394,069)	(259,053)		

To Pg. 4, L 31(p)

Order Paragraph		148-149	b Pg. 8, L. 20
Exhibit	a	36	N/A
		Attach. DJG-11	

SOUTHWEST GAS CORPORATION
SOUTHERN NEVADA
TEST YEAR ENDED 9/30/03
CAPITAL STRUCTURE AND RATE OF RETURN

Line No.	Description	Cost	Percent of Total	Weighted Cost
	(a)	(b)	(c)	(d)
1	Debt	5.07%	53.40%	2.71%
2	Preferred Stock	8.20%	6.60%	0.54%
3	Sub-total - excl. Common equity		60.00%	3.25%
4	Common Equity	10.50%	40.00%	4.20%
5	Total Capital		100.00%	7.45%
	Order Paragraph	37, 86	32	

PUBLIC UTILITIES COMMISSION OF NEVADA
SOUTHWEST GAS CORPORATION
SOUTHERN NEVADA
TEST YEAR ENDED 9/30/03
COMPUTATION OF REVENUE REQUIREMENT

LINE NO.	DESCRIPTION (A)	REFERENCE (B)	AMOUNT (C)	
1	Commission-adjusted rate base	Pg. 1, L.35, Col. D	$574,285,455	
2	Times: Required rate of return	Pg. 6, L. 5, Col. D	x 7.45%	
3	Required net operating income	Line 1 times Line 2	$42,784,266	To Pg. 1, L.22(F)
4	Add: applicable income taxes	Pg. 8, Line 15	13,083,237	To Pg. 1, L.18(F)
5	applicable uncollectible expense	Pg. 9, Line 10	1,193,148	
6	Commission adjusted test year expenses	Note 1 (Line 16, below)	89,412,790	
7	Total revenue requirement	Sum of Lines 3 thru 7	$146,473,441	To Pg. 1, L.3(F)
8	Less: Commission adjusted Total Revenues	Pg. 1, L. 3, Col. D	139,127,082	
9	Required increase in revenues	Line 8 minus Line 9	$7,346,359	To Pg. 1, L.3(E)

Note 1:

10	Commission adjusted test year expenses:	Pg. 1, L.16+18+20, Col. D	$101,100,475	
11	Less:			
12	income taxes included	Pg. 1, Line 18, Col. D	10,521,457	
13	uncollectible expense included	Pg. 9, Line 11	1,166,229	
14	Net expenses		$89,412,790	To Line 7

PUBLIC UTILITIES COMMISSION OF NEVADA
SOUTHWEST GAS CORPORATION
SOUTHERN NEVADA
TEST YEAR ENDED 9/30/03
COMPUTATION OF INCOME TAXES ON REVENUE REQUIREMENT

LINE NO.	DESCRIPTION (A)	REFERENCE (B)		AMOUNT (C)	
1	Commission-adjusted rate base	Pg. 1, L.35, Col. D		$574,285,455	
2	Times: Required rate of return	Pg. 6, L.5, Col. D	x	7.45%	
3	Required net operating income	Line 1 times Line 2		$42,784,266	
4	Add: adjustments to net operating income			0	
5	Adjusted required net operating income			$42,784,266	
6	Less: synchronized interest expense	Note 1, Line 20 (below)		(18,664,277)	
7	Add: permanent book-tax differences			254,510	
8	Less: ITC amortization			(194,604)	
9	Account 410 Amortizations			167,658	
10	Taxable base	Sum of Lines 5 thru 9		$24,347,553	
11	Times: federal income tax gross-up rate	Note 2, Line 23 (below)	x	53.846%	
12	Income taxes applicable to required return	Line 10 times Line 11		$13,110,183	
13	Less: ITC amortization			(194,604)	
14	Account 410 Amortizations			167,658	
15	Net income taxes applicable to required return	Lines 12 thru 14		$13,083,237	To Pg. 9, L.2 & 7, L.4
16	Less: income taxes, as adjusted by Commission	Pg. 1, L. 18, Col. D		10,521,457	
17	Income taxes applicable to revenue deficiency			$2,561,780	To Pg. 1, L.18(e)

Note 1:

18	Rate base	Pg. 1, L. 35, Col. D		$574,285,455	
19	Times: weighted cost of debt + preferred stock	Pg. 6, L.3, Col. D	x	3.25%	
20	Synchronized interest expense	Line 18 times Line 19		$18,664,277	To Line 6
21	Less: Company synchronized interest expense	Exhibit 2 at M, Sheet 1, Col. D		$17,804,406	
22	Increase (decrease) in synchronized interest	Line 20 minus Line 21		$859,871	
23	Income tax adjustment	Line 22 times 35% times -1		($300,955)	To Pg. 3, L.18(q)

Note 2:

24	Effective income tax rate (= R)	35%
25	Divided by: tax rate complement (= 1 - R)	65%
26	Income tax gross-up rate (= R / 1 - R)	53.846%

PUBLIC UTILITIES COMMISSION OF NEVADA
SOUTHWEST GAS CORPORATION
SOUTHERN NEVADA
TEST YEAR ENDED 9/30/03
COMPUTATION OF UNCOLLICTIBLE EXPENSE ON REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	REFERENCE		AMOUNT	
	(A)	(B)		(C)	
1	Required net operating income	Pg. 7, Line 3		$42,784,266	
2	Add: applicable income taxes	Pg. 8, Line 15		13,083,237	
3	adjusted test year operating expenses, net of				
4	taxes and uncollectible expense	Pg. 1, Col D, L.16 &		89,158,280	
5		Pg. 7, line 14			
6	gas costs	Exhibit 2 at H-9; J-1 at 6		168,098,683	
7	Revenue requirement, before uncollectible expense			$313,124,466	
8	Times: uncollectible gross-up rate	Note 1, Line 14 (below)	x	0.381%	
9	Uncollectible expense applicable to required net				
10	operating income	Line 6 times Line 7		$1,193,148	To Pg. 7, Line 6
11	Less: adjusted uncollectible expense, per Commission	Note 2		1,166,229	To Pg. 7, Line 13
12	Uncollectible expense applicable to revenue deficiency	Line 10 less Line 11		$26,919	To Pg. 1, L.7(E)
	Note 1:				
13	Uncollectible expense (= R)	Exhibit 2 at H-9		0.3796%	
14	Divided by: uncollectible rate complement (= 1 - R)			0.996204	
15	Uncollectible gross-up rate	Line 12 divided by Line 13		0.381%	To Line 7
	Note 2:				
16	Add: adjusted uncollectible expense, per Commission	Pg. 1, L.3, Col. (D)*R		$528,126	
17	uncollectible expense, gas costs	Exhibit 2 at H-5*R		638,103	
18	Commission Adjusted Uncollectable Expense			1,166,229	To Line 11
19	Less: Southwest uncollectible expense	Exhibit 2 at H-9		1,163,061	
20	Adjustment to uncollectible expense	Line 8 less Line 9		$3,168	To Pg. 4, L.7(r)

PUBLIC UTILITIES COMMISSION OF NEVADA
SOUTHWEST GAS CORPORATION
SOUTHERN NEVADA
TEST YEAR ENDING 9/30/03
CALCULATION OF NET / GROSS FACTORS

LINE NO.	DESCRIPTION (A)	COMPUTATION (B)		AMOUNT (C)
	Net to Gross:			
	Change in net operating income			1.00000
2	Add: Income tax factor	35% / 65%		0.53846
3				
4	Uncollectible factor	1.53846 * .00381	(1)	0.00586
5	Total change in revenue requirement			1.54432
	Gross to Net:			
6	Total change in revenue requirement			1.0000
7				
8	Uncollectible factor			(0.003796)
9	Income tax factor	35% * (1.000-.003796)		(0.3487)
10	Change in net operating income			0.64753

Note 1:

11	Uncollectible expense (= R)	0.3796%	
12	Divided by: uncol. rate complement (= 1 - R)	0.99620	
13	Uncollectible gross-up rate (= R / (1-R)) (L.11 / L.12)	0.00381	To Line 4

PUBLIC UTILITIES COMMISSION OF NEVADA
SOUTHWEST GAS CORPORATION
NORTHERN NEVADA
TEST YEAR ENDED 9/30/03
SUMMARY OF OPERATIONS AND RATE BASE

Line No.	Description (a)	Southwest Adjusted Amounts #REF! (b) Stmt. H, Pg. 1, Col (e)	Commission Adjustments (c) Pg. 4, Col (r)	As Adjusted (d) (=B+C)	Deficiency (e) Pg. 7-9	Total Revenue Requirement (f) (=D+E)
1	Operating Revenue	$31,406,819	$0	$31,406,819	$6,371,720	$37,778,539
1a	Other Revenue	0	18,000	18,000	0	18,000
2	Gas Cost	0	0	0	0	0
3	Operating Margin	$31,406,819	$18,000	$31,424,819	$6,371,720	$37,796,539
	Operating Expenses					
4	Other Gas Costs	$58,589	$0	$58,589	$0	$58,589
5	Transmission	0	0	0	0	0
6	Distribution	9,235,094	0	9,235,094	0	9,235,094
7	Customer Accounts	3,963,552	49	3,963,601	17,244	3,980,845
8	Customer Service & Information	12,463	0	12,463	0	12,463
9	Sales	0	0	0	0	0
	Administrative and General					
10	Northern Nevada Division	432,438	(236,930)	195,508	0	195,508
11	System Allocable	4,164,540	(4,659)	4,159,881	0	4,159,881
	Depreciation and Amortization					
12	Northern Nevada Division	7,119,379	(477,716)	6,641,663	0	6,641,663
	System Allocable	826,498	(193,578)	632,920	0	632,920
	Taxes Other Than Income	987,621	0	987,621	0	987,621
15	Regulatory Amortization	3,267	(3,000)	267	0	267
16	Subtotal Expenses	$26,803,443	($915,834)	$25,887,609	$17,244	$25,904,853
17	Net Operating Income before FIT	$4,603,376	$933,834	$5,537,210	$6,354,476	$11,891,686
18	Federal Income Taxes	(80,134)	297,023	216,889	2,227,202	2,444,091
19	Regulatory Amortization	0	0	0	0	0
20	Ratemaking Amortization - CP National	0	0	0	0	0
21	Total Other Expenses	($80,134)	$297,023	$216,889	$2,227,202	$2,444,091
22	Net Operating Income	$4,683,511	$636,811	$5,320,321	$4,127,274	$9,447,595
	Rate Base					
	Gas Plant in Service					
23	Northern Nevada Division	$158,347,542	($11,707)	$158,335,835		$158,335,835
24	System Allocable	9,622,206	(1,881,471)	7,740,735		7,740,735
25	Total Gross Plant	$167,969,747	($1,893,178)	$166,076,569		$166,076,569
	Accumulated Provision for Depreciation and Amortization					
26	Northern Nevada Division	$37,530,150	$0	$37,530,150		$37,530,150
27	System Allocable	4,770,932	(46,394)	4,724,538		4,724,538
28	Total Accumulated Provision for Depreciation and Amortization	$42,301,082	($46,394)	$42,254,688		$42,254,688
29	Net Plant in Service	$125,668,666	($1,846,784)	$123,821,882		$123,821,882
	Other Rate Base Items					
30	Materials and Supplies	3,138,277	0	3,138,277		3,138,277
31	Working Capital	687,722	76,273	763,995		763,995
32	Customer Advances	(1,773,923)	0	(1,773,923)		(1,773,923)
33	Deferred Taxes	(16,016,496)	375,574	(15,640,922)		(15,640,922)
34	Total Other Rate Base Items	($13,964,420)	$451,847	($13,512,573)		($13,512,573)
	Total Rate Base	$111,704,246	($1,394,937)	$110,309,309		$110,309,309
36	Rate of Return	4.19%		4.82%		8.56%

PUBLIC UTILITIES COMMISSION OF NEVADA
SOUTHWEST GAS CORPORATION
NORTHERN NEVADA
TEST YEAR ENDED 9/30/03
SUMMARY OF COMMISSION ADJUSTMENTS

Line No	Description	WMS Adj. No. 1	CCNC Adj. No. 2	SERP & EDCP Expense Adj. No. 3	Working Cash Adj. No. 4	Service Establishment Revenues Adj. No. 5	Late Charge Revenues Adj. No. 6	Medical Insurance Adj. No. 7
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Operating Revenue	$0	$0	$0	$0	$0	$0	$0
1a	Other Revenue	0	0	0	0	1,000	17,000	0
2	Gas Cost	0	0	0	0	0	0	0
3	Operating Margin	$0	$0	$0	$0	$1,000	$17,000	$0
	Operating Expenses							
4	Other Gas Costs	$0	$0	$0	$0	$0	$0	$0
5	Transmission	0	0	0	0	0	0	0
6	Distribution	0	0	0	0	0	0	0
7	Customer Accounts	0	0	0	0	0	0	0
8	Customer Service & Information	0	0	0	0	0	0	0
9	Sales	0	0	0	0	0	0	0
	Administrative and General							
10	Northern Nevada Division	0	0	(229,000)	0	0	0	(7,930)
11	System Allocable	0	0	(58,000)	0	0	0	(2,070)
	Depreciation and Amortization							
12	Northern Nevada Division	0	(977)	0	0	0	0	0
13	System Allocable	(185,583)	(7,995)	0	0	0	0	0
14	Taxes Other Than Income	0	0	0	0	0	0	0
15	Regulatory Amortization	0	0	0	0	0	0	0
16	Subtotal Expenses	($185,583)	($8,972)	($287,000)	$0	$0	$0	($10,000)
17	Net Operating Income before FIT	$185,583	$8,972	$287,000	$0	$1,000	$17,000	$10,000
18	Federal Income Taxes	64,954	0	100,450	0	350	5,950	3,500
19	Regulatory Amortization	0	0	0	0	0	0	0
20	Ratemaking Amortization	0	0	0	0	0	0	0
21	Total Other Expenses	$64,954	$0	$100,450	$0	$350	$5,950	$3,500
22	Net Operating Income	$120,629	$8,972	$186,550	$0	$650	$11,050	$6,500
	Rate Base							
	Gas Plant in Service							
23	Northern Nevada Division	$0	($11,707)	$0	$0	$0	$0	$0
24	System Allocable	(1,855,830)	(25,641)	0	0	0	0	0
25	Total Gross Plant	($1,855,830)	($37,348)	$0	$0	$0	$0	$0
	Accumulated Provision for Depreciation and Amortization							
26	Northern Nevada Division	$0	$0	$0	$0	$0	$0	$0
27	System Allocable	(46,394)	0	0	0	0	0	0
	Total Accumulated Provision for							
28	Depreciation and Amortization	($46,394)	$0	$0	$0	$0	$0	$0
29	Net Plant in Service	($1,809,436)	($37,348)	$0	$0	$0	$0	$0
	Other Rate Base Items							
30	Materials and Supplies	$0	$0	$0	$0	$0	$0	$0
31	Working Capital	0	0	372,000	(33,824)	0	0	0
32	Customer Advances	0	0	0	0	0	0	0
33	Deferred Taxes	375,574	0	0	0	0	0	0
34	Total Other Rate Base Items	$375,574	$0	$372,000	($33,824)	$0	$0	$0
35	Total Rate Base	($1,433,862)	($37,348)	$372,000	($33,824)	$0	$0	$0
	Order Paragraph / Attachment	106	114	132	150	153	157	171
	Exhibit	38	38	44	36	44	44	47
		Attch. KJP-2	Attchs. KJP-3, KJP-4 & 7	Attch. B-2, C-2.2	Attch. DJG-11	Attch. C-1.1	Attch. C-1.1	Attch. RLA-7

PUBLIC UTILITIES COMMISSION OF NEVADA
SOUTHWEST GAS CORPORATION
NORTHERN NEVADA
TEST YEAR ENDED 9/30/03
SUMMARY OF COMMISSION ADJUSTMENTS

Line No.	Description	Corporate Labor Adj. No. 8	DSM Amortization Adj. No. 9	Aircraft Liability Ins. Adj. No. 10	Paiute Allocation Adj. No. 11	AMT Prepaid Adj. No. 12	Annualized Depreciation Expense Adj. No. 13	Lead / Lag Study Adj. No. 14
	(a)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	Operating Revenue	$0	$0	$0	$0	$0	$0	$0
1a	Other Revenue	0	0	0	0	0	0	0
2	Gas Cost	0	0	0	0	0	0	0
3	Operating Margin	$0	$0	$0	$0	$0	$0	$0
	Operating Expenses							
4	Other Gas Costs	$0	$0	$0	$0	$0	$0	$0
5	Transmission	0	0	0	0	0	0	0
6	Distribution	0	0	0	0	0	0	0
7	Customer Accounts	0	0	0	0	0	0	0
8	Customer Service & Information	0	0	0	0	0	0	0
9	Sales	0	0	0	0	0	0	0
	Administrative and General							
10	Northern Nevada Division	0	0	0	0	0	0	0
11	System Allocable	52,873	0	(127)	2,665	0	0	0
	Depreciation and Amortization							
12	Northern Nevada Division	0	0	0	0	0	(476,739)	0
13	System Allocable	0	0	0	0	0	0	0
14	Taxes Other Than Income	0	0	0	0	0	0	0
15	Regulatory Amortization	0	(3,000)	0	0	0	0	0
16	Subtotal Expenses	$52,873	($3,000)	($127)	$2,665	$0	($476,739)	$0
17	Net Operating Income before FIT	($52,873)	$3,000	$127	($2,665)	$0	$476,739	$0
18	Federal Income Taxes	(18,506)	1,050	44	(933)	0	166,859	0
19	Regulatory Amortization	0	0	0	0	0	0	0
20	Ratemaking Amortization	0	0	0	0	0	0	0
21	Total Other Expenses	($18,506)	$1,050	$44	($933)	$0	$166,859	$0
22	Net Operating Income	($34,367)	$1,950	$83	($1,732)	$0	$309,880	$0
	Rate Base							
	Gas Plant in Service							
23	Northern Nevada Division	$0	$0	$0	$0	$0	$0	$0
24	System Allocable	0	0	0	0	0	0	0
25	Total Gross Plant	$0	$0	$0	$0	$0	$0	$0
	Accumulated Provision for Depreciation and Amortization							
26	Northern Nevada Division	$0	$0	$0	$0	$0	$0	$0
27	System Allocable	0	0	0	0	0	0	0
28	Total Accumulated Provision for Depreciation and Amortization	$0	$0	$0	$0	$0	$0	$0
29	Net Plant in Service	$0	$0	$0	$0	$0	$0	$0
	Other Rate Base Items							
30	Materials and Supplies	$0	$0	$0	$0	$0	$0	$0
31	Working Capital	0	0	0	0	900,921	0	(1,162,824)
32	Customer Advances	0	0	0	0	0	0	0
33	Deferred Taxes	0	0	0	0	0	0	0
34	Total Other Rate Base Items	$0	$0	$0	$0	$900,921	$0	($1,162,824)
35	Total Rate Base	$0	$0	$0	$0	$900,921	$0	($1,162,824)
	Order Paragraph / Attachment	172	176	184	188	203	Attch. 2	Attch. 3, Pg. 5
	Exhibit	3 & 47	44 Attch. A-1	47	40	37 Attch. RAB-6	N/A	N/A

BLIC UTILITIES COMMISSION OF NEVADA
SOUTHWEST GAS CORPORATION
NORTHERN NEVADA
TEST YEAR ENDED 9/30/03
'MMARY OF COMMISSION ADJUSTMENTS

Line No.	Description	Tax Exp - Int Synch Adj. No. 15	Uncollectible Expense Adj. No. 16	Total of Adjustments
	(a)	(p)	(q)	(r)
1	Operating Revenue	$0	$0	$0
1a	Other Revenue	0	0	18,000
2	Gas Cost	0	0	0
3	Operating Margin	$0	$0	$18,000
	Operating Expenses			
4	Other Gas Costs	$0	$0	$0
5	Transmission	0	0	0
6	Distribution	0	0	0
7	Customer Accounts	0	49	49
8	Customer Service & Information	0	0	0
9	Sales	0	0	0
	Administrative and General			
10	Northern Nevada Division	0	0	(236,930)
11	System Allocable	0	0	(4,659)
	Depreciation and Amortization			
12	Northern Nevada Division	0	0	(477,716)
13	System Allocable	0	0	(193,578)
14	Taxes Other Than Income	0	0	0
15	Regulatory Amortization	0	0	(3,000)
16	Subtotal Expenses	$0	$49	($915,834)
17	Net Operating Income before FIT	$0	($49)	$933,834
18	Federal Income Taxes	(26,678)	(17)	297,023
19	Regulatory Amortization	0	0	0
20	Ratemaking Amortization	0	0	0
21	Total Other Expenses	($26,678)	($17)	$297,023
22	Net Operating Income	$26,678	($32)	$636,811
	Rate Base			
	Gas Plant in Service			
23	Northern Nevada Division	$0	$0	($11,707)
24	System Allocable	0	0	(1,881,471)
25	Total Gross Plant	$0	$0	($1,893,178)
	Accumulated Provision for Depreciation and Amortization			
26	Northern Nevada Division	$0	$0	$0
27	System Allocable	0	0	(46,394)
28	Total Accumulated Provision for Depreciation and Amortization	$0	$0	($46,394)
29	Net Plant in Service	$0	$0	($1,846,784)
	Other Rate Base Items			
30	Materials and Supplies	$0	$0	$0
31	Working Capital	0	0	76,273
32	Customer Advances	0	0	0
33	Deferred Taxes	0	0	375,574
34	Total Other Rate Base Items	$0	$0	$451,847
35	Total Rate Base	$0	$0	($1,394,937)
	Order Paragraph / Attachment	Attch. 3, Pg. 8	Attch. 3, Pg. 9	
	Exhibit	N/A	N/A	

PUBLIC UTILITIES COMMISSION OF NEVADA
SOUTHWEST GAS CORPORATION
NORTHERN NEVADA
TEST YEAR ENDED 9/30/03
SUMMARY OF CASH WORKING CAPITAL

Ln.	Description	Refer.	As Filed SWG Cost	Commission Adjustment	Adjusted Total Cost	Adjusted Lag Days	Dollar Days
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	Cost of Gas		$57,534,393		$57,534,393	42.62	$2,452,115,830
2	Labor and Benefits		10,817,634		10,817,634	10.69	115,640,507
3	Pension Costs Charged to O&M		550,658		550,658	0.00	0
4	Supplemental Retirement Plan Expense		292,619		292,619	0.00	0
5	Prepayments Amortized to O&M		375,375		375,375	0.00	0
6	Uncollectible Accounts Expense		247,331		247,331	189.52	46,874,171
7	Prepaid Insurance Amortized to O&M		355,183		355,183	0.00	0
8	Building Lease Charged to O&M		119,805		119,805	0.00	0
9	Other O&M Expenses		5,132,510		5,132,510	33.97	174,351,365
10	Total O&M Expenses		75,425,508	0	75,425,508	36.98	2,788,981,873
11	Depreciation and Amortization	a	7,945,877	(7,945,877)	0	0.00	0
12	Taxes Other Than Income Taxes		987,621		987,621	26.64	26,310,223
13	Federal Income Taxes - Current		5,855,952		5,855,952	39.00	228,382,128
14	Deferred Income Taxes	a	(2,938,215)	2,938,215	0	0.00	0
15	Equity Return	a	5,512,605	(5,512,605)	0	0.00	0
16	Interest Expense	a,b	4,738,382	1,774	4,740,156	84.10	398,647,120
17	Total Revenue Requirement		97,527,730	(10,518,493)	87,009,237	39.56	3,442,321,344
18	No. Of Days in Test Period		365	365	365		
19	Avg. Daily Revenue Requirement [L17/L18]		267,199	(28,818)	238,381		
20	Lag in Receipt of Revenue					36.31	
21	Net Rev Lag (Exp Lead) [Lag Days, L20-L17]		1.45		(3.25)		
22	Cash Working Capital for Operating Expense [L19xL21]		$387,439	($1,162,824)	($775,385)		
				To Pg. 4, L 31(o)			
	Order Paragraph			148-149	b	Pg. 8, L. 20	
	Exhibit	a	36			N/A	
			Attach. DJG-11				

PUBLIC UTILITIES COMMISSION OF NEVADA
SOUTHWEST GAS CORPORATION
NORTHERN NEVADA
TEST YEAR ENDED 9/30/03
CAPITAL STRUCTURE AND RATE OF RETURN

Line No.	Description	Cost	Percent of Total	Weighted Cost
	(a)	(b)	(c)	(d)
1	Debt	7.16%	53.40%	3.82%
2	Preferred Stock	8.20%	6.60%	0.54%
3	Sub-total - excl. Common equity		60.00%	4.36%
4	Common Equity	10.50%	40.00%	4.20%
5	Total Capital		100.00%	8.56%
	Order Paragraph	37, 86	32	

PUBLIC UTILITIES COMMISSION OF NEVADA
SOUTHWEST GAS CORPORATION
NORTHERN NEVADA
TEST YEAR ENDED 9/30/03
COMPUTATION OF REVENUE REQUIREMENT

LINE NO	DESCRIPTION (A)	REFERENCE (B)		AMOUNT (C)	
1	Commission-adjusted rate base	Pg. 1, L.35, Col. D		$110,309,309	
2	Times: Required rate of return	Pg. 6, L. 5, Col. D	x	8.56%	
3	Required net operating income	Line 1 times Line 2		$9,447,595	To Pg. 1, L.22(F)
4	Add: applicable income taxes	Pg. 8, Line 15		2,444,091	To Pg. 1, L.18(F)
5	applicable uncollectible expense	Pg. 9, Line 10		264,624	
6	Commission adjusted expenses	Note 1 (Line 16, below)		25,640,229	
7	Total revenue requirement	Sum of Lines 3 thru 7		$37,796,539	To Pg. 1, L.3(F)
8	Less: Total Commission adjusted revenues	Pg. 1, L. 3, Col. D		(31,424,819)	
9	Required increase in revenues	Line 8 minus Line 9		$6,371,720	To Pg. 1, L.3(E)

Note 1:

10	Commission adjusted expenses	Pg. 1, L.16+18+20, Col. D	$26,104,497	
11	Less:			
12	income taxes included	Pg. 1, Line 18, Col. D	216,889	
13	uncollectible expense included	Pg. 9, Line 11	247,380	
14	Net expenses		$25,640,229	To Line 7

PUBLIC UTILITIES COMMISSION OF NEVADA
SOUTHWEST GAS CORPORATION
NORTHERN NEVADA
TEST YEAR ENDED 9/30/03
COMPUTATION OF INCOME TAXES ON REVENUE REQUIREMENT

LINE NO.	DESCRIPTION (A)	REFERENCE (B)	AMOUNT (C)	
1	Commission-adjusted rate base	Pg. 1, L.35, Col. D	$110,309,309	
2	Times: Required rate of return	Pg. 6, L.5, Col. D	x 8.56%	
3	Required net operating income	Line 1 times Line 2	$9,447,595	
4	Add: adjustments to net operating income		0	
5	Adjusted required net operating income		$9,447,595	
6	Less: synchronized interest expense	Note 1, Line 20 (below)	(4,814,604)	
7	Add: permanent book-tax differences		0	
8	Less: ITC amortization		(86,184)	
9	Account 410 Amortizations		53,301	
10	Taxable base	Sum of Lines 5 thru 9	$4,600,108	
11	Times: federal income tax gross-up rate	Note 2, Line 23 (below)	x 53.846%	
12	Income taxes applicable to required return	Line 10 times Line 11	$2,476,974	
13	Less: ITC amortization		(86,184)	
14	Account 410 Amortizations		53,301	
15	Net income taxes applicable to required return	Lines 12 thru 14	$2,444,091	To Pg. 9, L.2 & Pg. 7, L.4
16	Less: income taxes, as adjusted by Commission	P.g. 1, L. 18, Col. D	(216,889)	
17	Income taxes applicable to revenue deficiency		2,227,202	To Pg. 1, L.18(c)
	Note 1			
18	Rate base	Pg. 1, L. 35, Col. D	$110,309,309	
19	Times: weighted cost of debt + preferred stock	Pg. 6, L.3, Col. D	x 4.36%	
20	Synchronized interest expense	Line 18 times Line 19	$4,814,604	To Line 6
21	Less: Company synchronized interest expense	Exhibit 3 at M, Sheet 1, Col. D	$4,738,382	
22	Increase (decrease) in synchronized interest	Line 20 minus Line 21	$76,222	
23	Income tax adjustment	Line 22 times 35% times -1	($26,678)	To Pg. 4, L.18(p)
	Note 2			
24	Effective income tax rate (= R)		35%	
25	Divided by: tax rate complement (= 1 - R)		65%	
26	*Income tax gross-up rate (= R / 1 - R)*		53.846%	

PUBLIC UTILITIES COMMISSION OF NEVADA
SOUTHWEST GAS CORPORATION
NORTHERN NEVADA
TEST YEAR ENDED 9/30/03
COMPUTATION OF UNCOLLECTIBLE EXPENSE ON REVENUE REQUIREMENT

LINE NO	DESCRIPTION	REFERENCE		AMOUNT	
	(A)	(B)		(C)	
1	Required net operating income	Pg. 7, Line 3		$9,447,595	
2	Add: applicable income taxes	Pg. 8, Line 15		2,444,091	
3	adjusted test year operating expenses, net of				
4	taxes and uncollectible expense	Pg. 1, Col D, L.16 &		25,640,229	
5		Pg. 7, line 14			
6	gas costs	Exhibit 3 at H-9; J-1 at 6		59,981,263	
7	Revenue requirement, before uncollectible expense			$97,513,178	
8	Times: uncollectible gross-up rate	Note 1, Line 13 (below)	x	0.271%	
9	Uncollectible expense applicable to required net				
10	operating income	Line 6 times Line 7		$264,624	To Pg. 7, Line 6
11	Less: adjusted uncollectible expense, per Commission	Note 2		247,380	To Pg. 7, Line 13
12	Uncollectible expense applicable to revenue deficiency	Line 10 less Line 11		$17,244	To Pg. 1, L.7(E)
	Note 1:				
13	Uncollectible expense (= R)	Exhibit 3 at H-9		0.2706%	
14	Divided by: uncollectible rate complement (= 1 - R)			0.99729362	
15	Uncollectible gross-up rate	Line 11 divided by Line 12		0.271%	To Line 8
	Note 2:				
16	Add: adjusted uncollectible expense, per Commission	Pg. 1, L.3, Col. (D)*R		$85,048	
17	uncollectible expense, gas costs	Exhibit 3 at H-5*R		162,332	
18	Commission Adjusted Uncollectable Expense			247,380	To Line 11
19	Less: Southwest uncollectible expense	Exhibit 3 at H-9		247,331	
20	Adjustment to uncollectible expense	Line 8 less Line 9		$49	To Pg. 4, L.7(q)

PUBLIC UTILITIES COMMISSION OF NEVADA
SOUTHWEST GAS CORPORATION
NORTHERN NEVADA
TEST YEAR ENDING 9/30/03
CALCULATION OF NET / GROSS FACTORS

LINE NO.	DESCRIPTION (A)	COMPUTATION (B)		AMOUNT (C)
	Net to Gross:			
1	Change in net operating income			1.00000
2	Add: Income tax factor	35% / 65%		0.53846
3				
4	Uncollectible factor	1.53846 * .002706	(1)	0.00417
5	Total change in revenue requirement			1.54264
	Gross to Net:			
6	Total change in revenue requirement			1.0000
7				
8	Uncollectible factor			(0.002706)
9	Income tax factor	35% * (1.000-.002706)		(0.3491)
10	Change in net operating income			0.64824

Note 1:

11	Uncollectible expense (= R)	0.2706%	
12	Divided by: uncol. rate complement (= 1 - R)	0.99729	
13	Uncollectible gross-up rate (= R / (1-R)) (L.11 / L.12)	0.00271	To Line 4

SOUTHWEST GAS CORPORATION
2004 ARIZONA GENERAL RATE CASE
* * *

ACC LEGAL DIVISION DATA REQUEST NO. 7
SWG'S REQUEST NO. STAFF-BGG-7
(STAFF-BGG-7-1 THROUGH STAFF-BGG-7-24)

DOCKET NO.: G-01551A-04-0876
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 23, 2005

Request No. STAFF-BGG-7-3:

Please provide a complete listing of states and utilities which use a mechanism similar to the proposed conservation margin tracker. For each state and/or utility, please provide any materials Southwest has which document the mechanism(s) used by these other states and/or utilities.

Respondent: Pricing & Tariffs

Response:

The following is a list of natural gas local distribution companies which use or have requested a form of margin decoupling that Southwest is currently aware of:

Northwest Natural Gas Company/Oregon
Baltimore Gas and Electric Company/Maryland
Southern California Gas Company/California
San Diego Gas and Electric Company/California
Pacific Gas and Electric Company/California
Bay State Gas Company/Massachusetts
Black Stone Gas Company/Massachusetts
Colonial Gas Company/Massachusetts
Atmos Energy Corporation/Georgia
Citizens Gas/Indiana

Another approach to residential margin stabilization is the development of straight fixed variable distribution rates. This has been accomplished in the state of Georgia for Atlanta Gas Light Company.

The requested materials are attached.

ALL-STATE LEGAL®
EXHIBIT
S-7 23
Admitted

SOUTHWEST GAS CORPORATION
2004 ARIZONA GENERAL RATE CASE
* * *

ACC LEGAL DIVISION DATA REQUEST NO. 7
SWG'S REQUEST NO. STAFF-BGG-7
(STAFF-BGG-7-1 THROUGH STAFF-BGG-7-24)

DOCKET NO.:	G-01551A-04-0876
COMMISSION:	ARIZONA CORPORATION COMMISSION
DATE OF REQUEST:	MARCH 23, 2005

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Atmos Energy Corporation/Georgia
Citizens Gas/Indiana

Another approach to residential margin stabilization is the development of straight fixed variable distribution rates. This has been accomplished in the state of Georgia for Atlanta Gas Light Company. The requested materials are attached.

Supplement to Response - June 13, 2005:

See attachments: : (1) *"Impact of Conservation on Gas Margins and Financial Stability in The Gas LDC Sector,"* a Special Comment dated June 2005, published by Moody's Investors Service; and (2) *"A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural"* published March 31, 2005, by Christensen Associates Energy Consulting.

***

Docket G-01551A-04-0876
Data Req. STAFF-BGG-7-3
Supplement to Response - June 13, 2005

CHRISTENSEN
ASSOCIATES
ENERGY CONSULTING

Economic Analysis and Consulting

A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural

by

Daniel G. Hansen
Steven D. Braithwait

March 31, 2005

Christensen Associates Energy Consulting, LLC
4610 University Avenue, Suite 700
Madison, Wisconsin 53705-2164

Voice 608.231.2266 Fax 608.231.2108

1. INTRODUCTION AND BACKGROUND

Traditional rate-of-return regulation may create incentives for energy utilities that are counter to public policy objectives. In the case of natural gas, this occurs in large part because utilities have costs that are both fixed and variable, but collect revenue to recover those costs primarily through volumetric prices (*i.e.*, retail $/therm prices applied to consumers' energy consumption). To recover their fixed costs, including their allowed return on capital, utilities typically forecast the total amount of energy they expect to sell in a given period, and set a price that will recover the appropriate amount of revenue toward fixed costs on the planned level of sales. This process tends to produce the following outcomes:

- The utility has an incentive to under-forecast sales for the rate-making period, thus increasing the retail price and improving the opportunity to recover fixed costs. The regulatory agency has a corresponding interest in over-stating sales forecasts, which would lead to lower prices. The resulting contrast in incentives typically leads to contentious rate cases.
- Variation in consumers' energy consumption due to factors such as unexpected weather conditions causes variation in both consumers' bills and the utility's net revenue (*i.e.*, revenue toward fixed-cost recovery).
- Once rates are set, the utility has a disincentive to take actions to encourage their customers to adopt energy efficient practices that may result in lower sales, as this will reduce their net revenues, and thus their ability to recover their fixed costs.

Consequently, utilities and regulatory agencies in a number of states have experimented with alternative mechanisms designed to alter some of the above incentives and outcomes. In 2002, the Oregon Public Utilities Commission (Commission) approved a Distribution Margin Normalization (DMN) mechanism for Northwest Natural Gas Company (NW Natural). As part of the Order, the Commission also approved NW Natural's proposal for Public Purposes Funding to support low-income bill payment assistance, low-income weatherization assistance, and enhanced energy efficiency programs. Finally, the Order imposed service quality standards on NW Natural, specifying penalties associated with violating specific service quality measures.

The Commission Order implementing DMN required NW Natural to submit an independent study regarding the effectiveness of the mechanism. The study will contribute to the process of determining whether to continue DMN beyond September 30, 2005. NW Natural has retained Christensen Associates Energy Consulting, LLC (CAEC) to perform this study, and has expanded the scope of the study to also include a partial evaluation of the Weather Adjusted Rate Mechanism (WARM) as well as a comparison of the combination of DMN and WARM to a full decoupling mechanism.

The report is organized as follows. Section 2 provides an overview of DMN, including a description of the calculations and its expected incentive effects. Section 3 provides a similar overview of WARM. Sections 2 and 3 focus on *theoretical* evaluations of DMN and WARM, or what we would expect to happen given the calculations contained in the mechanisms. Section 4 presents data and analysis regarding the effects of DMN, including revenue effects, changes in marketing efforts, organizational changes, financial effects, and service quality issues. Section 5 compares DMN to other rate mechanisms that may be able to achieve similar goals. Section 6 provides a summary and conclusions, including answers to the specific questions raised by the Commission in Order 02-634.

2. OVERVIEW OF DISTRIBUTION MARGIN NORMALIZATION[1]

2.1 Description of Mechanism

A primary goal of DMN is to reduce the uncertainty around NW Natural's distribution fixed cost recovery. That is, because distribution fixed costs are recovered through volumetric rates that are established based upon an expected level of sales, deviations from expected usage (caused by weather, economic conditions, price changes, random variations, etc.) will affect the amount of fixed costs recovered. In addition, by ensuring that the utility recovers its fixed costs regardless of customer usage levels, DMN reduces the utility's disincentive to promote energy efficiency. The DMN mechanism agreed to in Oregon is limited to "decoupling" revenues associated with 90% of the non-weather induced variation in usage for residential and commercial customers.

2.1.1 Elasticity Adjustment

There are two ways in which DMN affects revenues: the *elasticity adjustment* and the *deferral component*. The elasticity adjustment adjusts margin recovery for the effects that changes in retail tariff prices are expected to have on use per customer (*e.g.*, customers are expected to reduce consumption if natural gas prices increase). To understand the elasticity adjustment, consider an example in which the retail price increases over a particular time period. The elasticity adjustment mechanism first adjusts original "baseline" use per customer downward (using a price elasticity value specified in the tariff) to account for the fact that customers are expected to reduce usage when prices increase. This reduction in baseline usage is then used to calculate the increase in the dollar per therm margin required to keep the allowed fixed cost recovery constant on a per-customer basis. This new margin value is then passed through to the standard tariff, which in this example implies increasing the per therm rate. Ultimately, the change in the baseline use per customer value produced by the elasticity adjustment also affects the deferral component of DMN, which is described in detail later in this section.

The revenue effects of the elasticity adjustment alone are described in Equations 1a through 1c.[2]

Equation 1a: Elasticity Adjustment Revenues = $(M' - M) * Q^{A,M}$

[1] This mechanism has also been referred to as the Partial Decoupling Mechanism (PDM) and the Conservation tariff.

[2] For simplicity, we represent the calculations in the first year after a rate case, so that the initial margin (M) and baseline use per customer (QPC^B) are determined in the rate case. In practice, each year's DMN adjustment uses the baseline use per customer and margin values from the previous year.

Schedule No. G-10

LOW INCOME RESIDENTIAL GAS SERVICE

APPLICABILITY

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

TERRITORY

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

RATES

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

MINIMUM CHARGE

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

SPECIAL CONDITIONS

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

EXHIBIT
S-3
Admitted

EXHIBIT
S-27
Admitted

SECTION NO. 6
SERVICE LINES AND ESTABLISHMENTS

A. Priority and Timing of Service Establishments

1. After an applicant has complied with the Company's application and deposit requirements and has been accepted for service by the Company, the Company shall schedule that Customer for service establishment.

2. Service establishment shall be scheduled for completion within five (5) working days of the date the Customer has been accepted for service, except in those instances when the Customer requests service establishment beyond the five (5) working day limitation.

3. When the Company has made arrangements to meet with a Customer for service establishment purposes and the Company or the Customer cannot make the appointment during the prearranged time, the Company shall reschedule the service establishment appointment to the satisfaction of both parties.

4. The Company shall schedule service establishment appointments within a maximum range of four (4) hours during normal working hours, unless another time frame is mutually acceptable to the Company and the Customer.

5. Service establishments shall be made only by qualified Company service personnel.

6. For the purpose of this rule, service establishments can occur only when the Customer's facilities are ready and acceptable to the Company and the Company needs only to install or read a meter or turn the service on.

7. A fee for service establishment, re-establishment, or reconnection of service may be charged at a rate on file with and approved by the ACC. Whenever the applicant requests after-hours handling of his request, the Company shall charge an additional fee on file with and approved by the ACC unless a special call out is required. If a special call out is required, the charge shall be for a minimum of one hour at the Company's then prevailing after-hours rate for the service work on Customer's premises. Special handling of calls and the related charges shall be made only on request of the applicant.

B. Facilities

1. Customer Provided Facilities

   a. An applicant for service shall be responsible for the safety and maintenance of all Customer piping from the point of delivery to the point of consumption.

   b. Meters shall be installed in a location suitable to the Company where the meters will be safe from street traffic, readily and safely accessible for reading, testing and inspection, and where such activities will cause the least interference and inconvenience to the Customer. The Customer shall provide, without cost to the Company and at a suitable and easily accessible location, sufficient and proper space for the installation of meters.

APPLICANT

EXHIBIT
A-1
Admitted

SOUTHWEST GAS CORPORATION

Docket No. G-01551A-04-0876

2004
ARIZONA
GENERAL RATE CASE

APPLICATION
ANNUAL REPORT
TARIFF SHEETS

Volume I

2004
ARIZONA
GENERAL RATE CASE

APPLICATION
ANNUAL REPORT
TARIFF SHEETS

Volume I

Application

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

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

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

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

Applicant

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

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

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

Corporate Headquarters; Communications

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

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

Statutory Authority

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

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

Supporting Documentation

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

Nature of Relief Sought by Southwest

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

Circumstances Justifying Relief

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

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

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

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

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

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

<u>The Overall Theme</u>

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

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

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

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

Conservation Margin Tracker

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

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

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

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

Line Extension Policy and Practices

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

Southern Arizona Pipe Replacements

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

Witness Testimony

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

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

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

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

Randi Aldridge [rate base, expenses and allocations]

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

Frank Hanley [cost of common equity]

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

Christy Berger [class cost of service studies]

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

Edward Gieseking [rate design policy and conservation margin tracker]

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

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

Request for Implementation of New Rates by November 1, 2005

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

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

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

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

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

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

RESPECTFULLY SUBMITTED this 8th day of December, 2004.

SOUTHWEST GAS CORPORATION

Andrew W. Bettwy
Karen S. Haller
Legal Department
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Las Vegas, Nevada 89102
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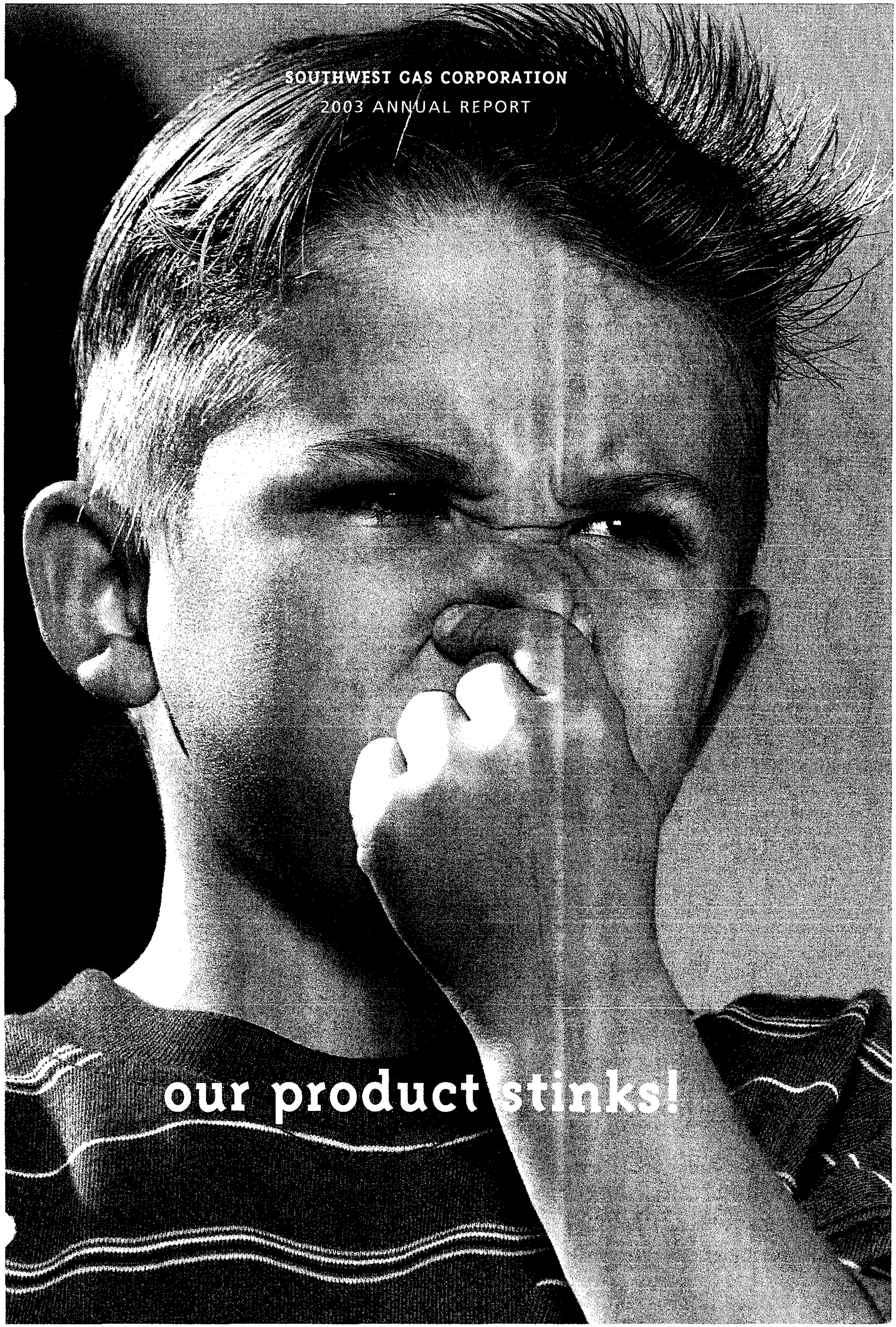
(702) 252-7283 - FAX
andy.bettwy@swgas.com

Annual Report


SOUTHWEST GAS CORPORATION
2003 ANNUAL REPORT
our product stinks!

but we made
it smell bad for
a good reason

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

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

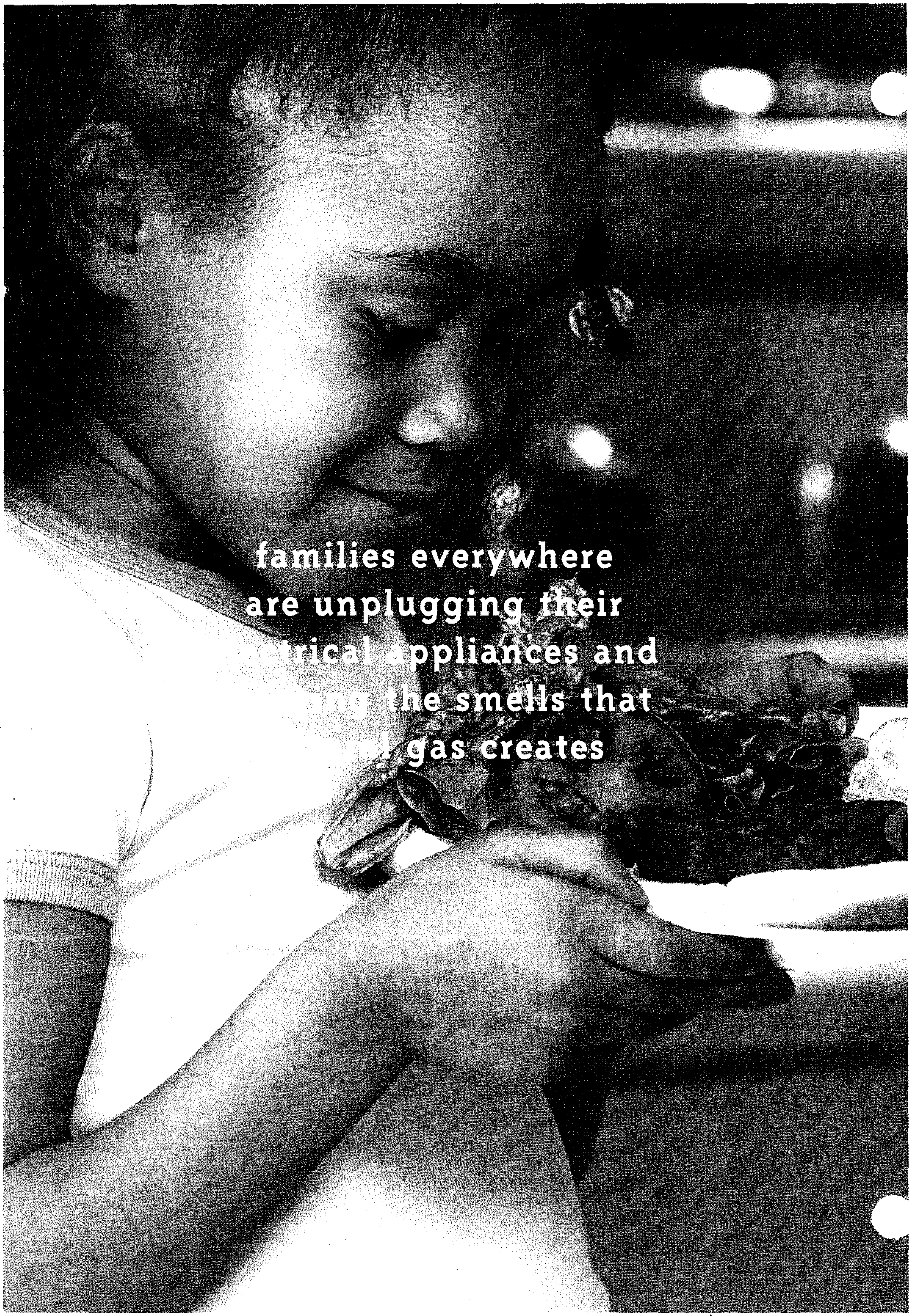
But natural gas does provide some good smells, too. There's nothing better than the aroma of fresh-baked cookies directly from the oven, or what could be better than the great smell of sauce-smothered ribs simmering on a natural gas barbecue? Our mouths water just thinking about it.

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

our "stink" helps create the amazing smells of home

cookies bring out the kid in all of us

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


families everywhere
are unplugging their
ctrical appliances and
the smells that
gas creates

grill of our dreams

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

hot bubble bath soothes the senses

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


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

aah. soft, fluffy, fresh-smelling towels

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

gas has never smelled so good

to our shareholders

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Sincerely,

Thomas Y. Hartley
Chairman of the Board

Michael O. Maffie
Chief Executive Officer

a brief farewell

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

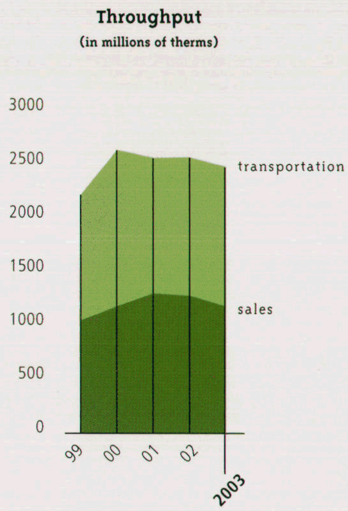
Exciting, challenging, exasperating and many other things. After more than 25 years, we've decided it's time that the "next generation" has their turn and we're confident they're up to the task. We couldn't have asked to spend 25 plus years of our careers with a better company. Southwesters are a unique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

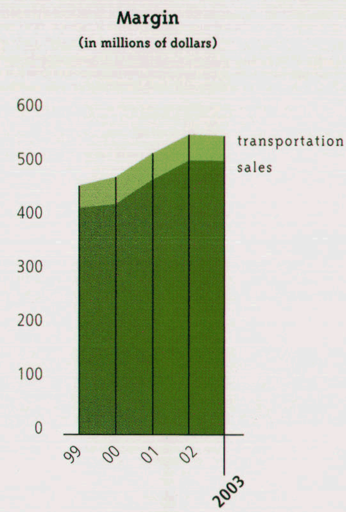
Michael O. Maffie
Chief Executive Officer

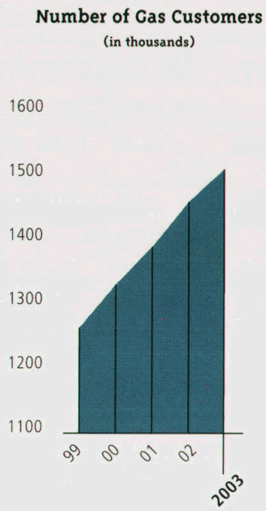
after over 25 years at southwest gas, mike and ed are retiring

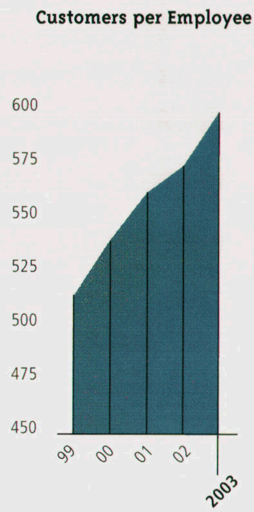
Edward S. Zub
Executive Vice President/Consumer Resources and Energy Services (front)

Michael O. Maffie
Chief Executive Officer (back)

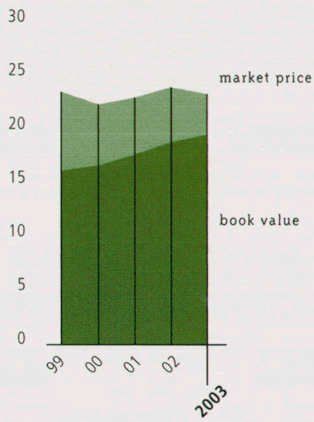

Throughput
(in millions of therms)
3000
2500
2000
1500
1000
500
0
transportation
sales
99
00
01
02
2003


Margin
(in millions of dollars)
600
500
400
300
200
100
0
transportation
sales
99
00
01
02
2003

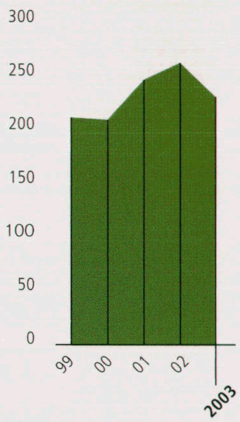

Number of Gas Customers
(in thousands)
1600
1500
1400
1300
1200
1100
99
00
01
02
2003


Customers per Employee
600
575
550
525
500
475
450
99
00
01
02
2003

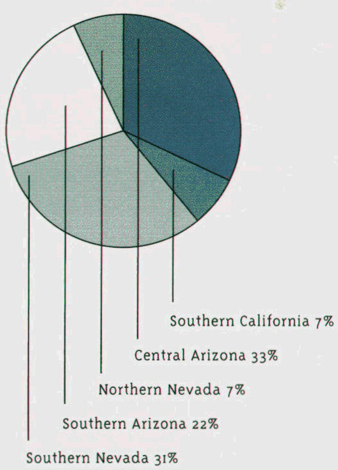
Market Price Relative to Book Value
(in dollars)



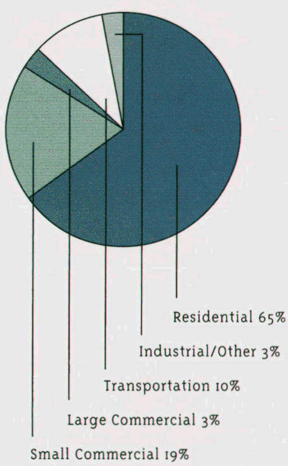
Construction Expenditures Gas Segment
(in millions of dollars)



Customers by Division
(December 31, 2003)

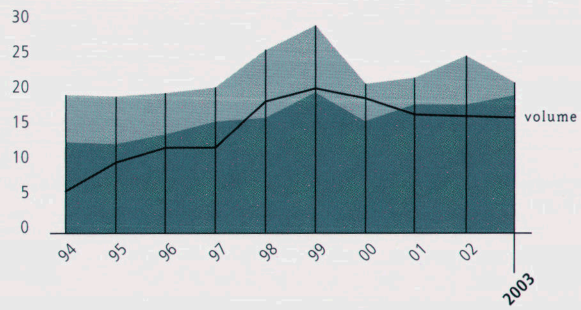


Margin by Customer Class
(2003)



Stock Prices & Trading Volume per Year

(stock prices in dollars, volume in millions)



consolidated selected financial statistics

(thousands of dollars, except per share amounts)

YEAR ENDED DECEMBER 31,	2003	2002	2001	2000	1999
Operating revenues	$ 1,231,004	$ 1,320,909	$ 1,396,688	$ 1,034,087	$ 936,866
Operating expenses	1,095,899	1,174,410	1,262,705	905,457	805,654
Operating income	$ 135,105	$ 146,499	$ 133,983	$ 128,630	$ 131,212
Net income	$ 38,502	$ 43,965	$ 37,156	$ 38,311	$ 39,310
Total assets at year end	$ 2,608,106	$ 2,432,928	$ 2,369,612	$ 2,232,337	$ 1,923,442
CAPITALIZATION AT YEAR END					
Common equity	$ 630,467	$ 596,167	$ 561,200	$ 533,467	$ 505,425
Mandatorily redeemable preferred trust securities	—	60,000	60,000	60,000	60,000
Subordinated debentures	100,000	—	—	—	—
Long-term debt	1,121,164	1,092,148	796,351	896,417	859,291
	$ 1,851,631	$ 1,748,315	$ 1,417,551	$ 1,489,884	$ 1,424,716
COMMON STOCK DATA					
Return on average common equity	6.3%	7.5%	6.8%	7.4%	8.0%
Earnings per share	$ 1.14	$ 1.33	$ 1.16	$ 1.22	$ 1.28
Diluted earnings per share	$ 1.13	$ 1.32	$ 1.15	$ 1.21	$ 1.27
Dividends paid per share	$ 0.82	$ 0.82	$ 0.82	$ 0.82	$ 0.82
Payout ratio	72%	62%	71%	67%	64%
Book value per share at year end	$ 18.42	$ 17.91	$ 17.27	$ 16.82	$ 16.31
Market value per share at year end	$ 22.45	$ 23.45	$ 22.35	$ 21.88	$ 23.00
Market value per share to book value per share	122%	131%	129%	130%	141%
Common shares outstanding at year end (000)	34,232	33,289	32,493	31,710	30,985
Number of common shareholders at year end	22,616	22,119	23,243	24,092	22,989
Ratio of earnings to fixed charges	1.60	1.68	1.59	1.60	1.78

natural gas operations

(thousands of dollars)

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

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

EXECUTIVE SUMMARY

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

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

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

consolidated results of operations

(thousands of dollars, except per share amounts)

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

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

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

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

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

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

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

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

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

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

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

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

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

RESULTS OF NATURAL GAS OPERATIONS

(thousands of dollars)

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

2003 vs. 2002

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

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

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

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

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

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

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

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

2002 vs. 2001

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

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

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

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

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

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

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

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

RATES AND REGULATORY PROCEEDINGS

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

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

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

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

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

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

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PGA FILINGS

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

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

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

OTHER FILINGS

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

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

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

CAPITAL RESOURCES AND LIQUIDITY

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

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

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

asset purchases

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

2003 financing activity

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

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

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

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

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

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

2004 construction expenditures and financing

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

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

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

off balance sheet arrangements

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

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

contractual obligations

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

CONTRACTUAL OBLIGATIONS

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

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

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

Estimated pension funding for 2004 is $14 million.

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liquidity

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

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

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

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

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

security ratings

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

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

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

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

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

inflation

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

RESULTS OF CONSTRUCTION SERVICES

(thousands of dollars)

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

2003 vs. 2002

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

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

2002 vs. 2001

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

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

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

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

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

APPLICATION OF CRITICAL ACCOUNTING POLICIES

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

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

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

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

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

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

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

FORWARD-LOOKING STATEMENTS

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

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

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

COMMON STOCK PRICE AND DIVIDEND INFORMATION

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

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

southwest gas corporation
consolidated balance sheets

(thousands of dollars, except par value)

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

southwest gas corporation
consolidated balance sheets

(thousands of dollars, except par value)

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

The accompanying notes are an integral part of these statements.

southwest gas corporation
consolidated statements of income

(in thousands, except per share amounts)

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

The accompanying notes are an integral part of these statements.

southwest gas corporation
consolidated statements of cash flows

(thousands of dollars)

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

The accompanying notes are an integral part of these statements.

southwest gas corporation
consolidated statements of stockholders' equity

(in thousands, except per share amounts)

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

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

The accompanying notes are an integral part of these statements.

notes to consolidated financial statements

NOTE 1
summary of significant accounting policies

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

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

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

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

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

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

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

notes to consolidated financial statements

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

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

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

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

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

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

notes to consolidated financial statements

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

(in thousands)

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

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

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

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

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

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

notes to consolidated financial statements

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

(thousands of dollars, except per share amounts)

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

NOTE 2
utility plant

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

(thousands of dollars)

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

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

notes to consolidated financial statements

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

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

(thousands of dollars)

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

notes to consolidated financial statements

NOTE 3
receivables and related allowances

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

(thousands of dollars)

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

NOTE 4
regulatory assets and liabilities

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

notes to consolidated financial statements

The following table represents existing regulatory assets and liabilities:

(thousands of dollars)

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

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

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

NOTE 5
preferred securities

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

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

notes to consolidated financial statements

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

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

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

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

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

notes to consolidated financial statements

NOTE 6
long-term debt

(thousands of dollars)

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

notes to consolidated financial statements

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

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

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

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

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

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

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

notes to consolidated financial statements

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

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

NOTE 7
short-term debt

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

NOTE 8
commitments and contingencies

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

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

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

notes to consolidated financial statements

NOTE 9
employee benefits

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

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

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

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

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

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

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

notes to consolidated financial statements

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

(thousands of dollars)

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

notes to consolidated financial statements

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

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

components of net periodic benefit cost:

(thousands of dollars)

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

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

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

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

notes to consolidated financial statements

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

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

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

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

(thousands of options)

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

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

(thousands of options)

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

notes to consolidated financial statements

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

(thousands of shares)

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

NOTE 10
income taxes

Income tax expense (benefit) consists of the following:

(thousands of dollars)

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

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

(thousands of dollars)

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

notes to consolidated financial statements

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

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

Deferred tax assets and liabilities consist of the following:

(thousands of dollars)

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

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

notes to consolidated financial statements

NOTE 11
segment information

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

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

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

(thousands of dollars)

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

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

notes to consolidated financial statements

(thousands of dollars)

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

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

NOTE 12
quarterly financial data (unaudited)

(thousands of dollars, except per share amounts)

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

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

notes to consolidated financial statements

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

NOTE 13
merger-related litigation settlements

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

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

NOTE 14
acquisition of black mountain gas company

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

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

(thousands of dollars)

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

report of independent auditors

To the Shareholders of
Southwest Gas Corporation:

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

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

PricewaterhouseCoopers LLP

Los Angeles, California
March 11, 2004

report of independent public accountants

To the Shareholders of
Southwest Gas Corporation:

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

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

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

ARTHUR ANDERSEN LLP

Las Vegas, Nevada
February 8, 2002

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

shareholder information

STOCK LISTING INFORMATION

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

ANNUAL MEETING

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

DIVIDEND REINVESTMENT AND STOCK PURCHASE PLAN

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

the DRSPP features include:

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

for more information contact:

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

DIVIDENDS

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

INVESTOR RELATIONS

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

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

TRANSFER AGENT

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

REGISTRAR

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

AUDITORS

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

Board of Directors and Officers

DIRECTORS

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

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

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

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

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

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

MICHAEL B. JAGER
Newport Beach, California
Private Investor

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

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

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

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

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

OFFICERS

MICHAEL O. MAFFIE
Chief Executive Officer

JEFFREY W. SHAW
President

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

JAMES P. KANE
Executive Vice President/
Operations

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

JAMES F. LOWMAN
Senior Vice President/
Central Arizona Division

THOMAS R. SHEETS
Senior Vice President/
Legal Affairs and General Counsel

DUDLEY J. SONDENO
Senior Vice President/
Chief Knowledge and
Technology Officer

THOMAS J ARMSTRONG
Vice President/Gas Resources
and Energy Services

ROY R. CENTRELLA
Vice President/Controller/
Chief Accounting Officer

CAROLD L. CLARK
Vice President/
Southern Nevada Division

FRED W. COVER
Vice President/Human Resources

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

EDWARD A. JANOV
Vice President/Finance

KENNETH J. KENNY
Treasurer

ROGER C. MONTGOMERY
Vice President/Pricing

CHRISTINA A. PALACIOS
Vice President/
Southern Arizona Division

DENNIS REDMOND
Vice President/
Northern Nevada Division

ANITA M. ROMERO
Vice President/
Southern California Division

ROBERT J. WEAVER
Vice President/
Information Services

JAMES F. WUNDERLIN
Vice President/Engineering

SOUTHWEST GAS CORPORATION
5241 SPRING MOUNTAIN ROAD
LAS VEGAS, NEVADA 89150

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

Proposed Tariff Sheets

SOUTHWEST GAS CORPORATION
PROPOSED ARIZONA TARIFF REVISIONS

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

SOUTHWEST GAS CORPORATION
PROPOSED ARIZONA TARIFF REVISIONS
(Continued)

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

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

PROPOSED TARIFF SHEET

Second Revised A.C.C. Sheet No. 2
Canceling First Revised A.C.C. Sheet No. 2

TABLE OF CONTENTS

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

Issued On ____________ Docket No. ____________

Issued by
John P. Hester
Vice President

Effective ____________ T
Decision No. ____________ T

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

PROPOSED TARIFF SHEET

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

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John P. Hester
Vice President

Effective ____________
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(Continued)

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

PROPOSED TARIFF SHEET

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

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

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

Issued On ____________ Issued by John P. Hester Vice President Effective ____________
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SOUTHWEST GAS CORPORATION
P.O. Box 98510
Las Vegas, Nevada 89193-8510
Arizona Gas Tariff No. 7
Arizona Division

Sixty-Third Revised A.C.C. Sheet No. 12
Canceling Sixty-Second Revised A.C.C. Sheet No. 12

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

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

Issued On ______________ Issued by John P. Hester, Vice President Effective ______________
Docket No. ______________ Decision No. ______________

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

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

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

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

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

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

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

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

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

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

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

N

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

PROPOSED TARIFF SHEET

	Ninth Revised	A.C.C. Sheet No.	14
Canceling	Eighth Revised	A.C.C. Sheet No.	14

HELD FOR FUTURE USE D/N

Issued On ______________ Issued by John P. Hester Vice President Effective ______________
Docket No. ______________ Decision No. ______________

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

PROPOSED TARIFF SHEET

Fourth Revised A.C.C. Sheet No. 15
Canceling Third Revised A.C.C. Sheet No. 15

STATEMENT OF RATES
OTHER SERVICE CHARGES [1/]

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

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

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

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

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

Issued On ____________ Issued by John P. Hester Vice President Effective ____________
Docket No. ____________ Decision No. ____________

Schedule No. G-5

SINGLE-FAMILY RESIDENTIAL GAS SERVICE C

APPLICABILITY

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

TERRITORY

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

RATES

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

MINIMUM CHARGE

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

SPECIAL CONDITIONS

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

PURCHASED GAS ADJUSTMENT CLAUSE

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

RULES AND REGULATIONS

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

Schedule No. G-5

SINGLE-FAMILY RESIDENTIAL GAS SERVICE
(Continued)

N

LOW INCOME DISCOUNT

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

2. Eligible customers will pay a discounted Basic Service Charge of $7.00 per month, and the commodity charges for low income customers will be discounted by fifteen-percent from the Rate Schedule No. G-5 Currently Effective Tariff Rate commencing with the next regularly scheduled billing period after the Utility has received the customer's properly completed application form or recertification.

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

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

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

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

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

D

Schedule No. G-6

MULTI-FAMILY RESIDENTIAL GAS SERVICE

APPLICABILITY

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

TERRITORY

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

RATES

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

MINIMUM CHARGE

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

SPECIAL CONDITIONS

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

PURCHASED GAS ADJUSTMENT CLAUSE

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

RULES AND REGULATIONS

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

Schedule No. G-6

N

MULTI-FAMILY RESIDENTIAL GAS SERVICE
(Continued)

LOW INCOME DISCOUNT

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

D

HELD FOR FUTURE USE

D/N

Schedule No. G-25

GENERAL GAS SERVICE

APPLICABILITY

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

TERRITORY

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

RATES

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

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

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

2. Transportation-Eligible General Gas Service C

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

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

Schedule No. G-30

OPTIONAL GAS SERVICE

APPLICABILITY

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

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

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

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

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

TERRITORY

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

RATES

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

HELD FOR FUTURE USE D/N

Schedule No. G-40

AIR-CONDITIONING GAS SERVICE

APPLICABILITY

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

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

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

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

TERRITORY

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

RATES

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

MINIMUM CHARGE

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

Schedule No. G-45

STREET LIGHTING GAS SERVICE

APPLICABILITY

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

TERRITORY

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

RATES

D

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

D

SPECIAL CONDITIONS

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

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

Schedule No. G-60

ELECTRIC GENERATION GAS SERVICE C/N

APPLICABILITY

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

TERRITORY

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

RATES

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

MINIMUM CHARGE

The minimum charge per meter is the basic service charge.

SPECIAL CONDITIONS

1. Gas service under this schedule is not available unless accompanied by a signed contract for a minimum of one year as the precedent to service under this schedule, and said contract shall continue in force and effect from year to year thereafter until either the Utility or the customer shall give the other written notice of a desire to terminate the same at least 30 days prior to the expiration of any such year. If the customer permanently ceases operation, such contract shall not thereafter continue in force.
2. Gas service under this schedule is not available for "standby" or occasional temporary service.
3. Customers initiating service after __________ (the effective date of rates in this case) whose installed facilities exceed 5 megawatts in name plate capacity will be required to take transportation service or, if qualified, enter into a Special Procurement Agreement under Rate Schedule No. G-30. N

N

Schedule No. G-60

ELECTRIC GENERATION GAS SERVICE C/N
(Continued)

SPECIAL CONDITIONS *(Continued)*

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

PURCHASED GAS ADJUSTMENT CLAUSE

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

RULES AND REGULATIONS

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

Schedule No. G-75

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

APPLICABILITY

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

TERRITORY

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

RATES

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

MINIMUM CHARGE

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

SPECIAL CONDITIONS

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

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

HELD FOR FUTURE USE

D/N

Schedule No. T-1

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS

1. AVAILABILITY

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

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

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

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

2. APPLICABILITY AND CHARACTER OF SERVICE

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

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

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

Schedule No. T-1

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
(Continued)

3. RATES

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

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

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

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

Schedule No. T-1

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
(Continued)

3. RATES *(Continued)*

D

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

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

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

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

Schedule No. T-1

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
(Continued)

3. RATES *(Continued)*

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

4. MINIMUM CHARGE

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

5. FORCE MAJEURE

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

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

Schedule No. T-1

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
(Continued)

7. TRANSPORTATION IMBALANCE SERVICE *(Continued)*

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

7.2 Payment for Excess Imbalances

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

Schedule No. T-1

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
(Continued)

7. TRANSPORTATION IMBALANCE SERVICE *(Continued)*

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

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

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

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

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

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

HELD FOR FUTURE USE D/N

SPECIAL SUPPLEMENTARY TARIFF
PURCHASED GAS COST ADJUSTMENT PROVISION

APPLICABILITY

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

CHANGE IN RATES

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

BANK BALANCE

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

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

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

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

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

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

PROPOSED TARIFF SHEET

First Revised A.C.C. Sheet No. 91-92
Canceling Original A.C.C. Sheet No. 91-92

HELD FOR FUTURE USE D/N

Issued On ____________________
Docket No. ____________________

Issued by
John P. Hester
Vice President

Effective ____________________ T
Decision No. ____________________ T

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY RELEASE SERVICE PROVISION T

D

A. APPLICABILITY

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

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

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

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

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

B. RATES AND BIDDING PROCEDURES

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

C. BILLING

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

D. RECALL OF RELEASED CAPACITY

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

1. Force majeure situations occurring on the upstream pipeline system; or
2. To protect service to Priority 1 and Priority 2 customers; or
3. When the Utility's core demand for upstream pipeline capacity is greater than the Utility's current billing determinant or contract demand on the applicable interstate pipeline(s); or
4. If the acquiring shipper fails to remit payment for services rendered to the interstate pipeline when such amounts are due.

E. ACCOUNTING FOR CAPACITY RELEASE CREDITS

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

N

SPECIAL SUPPLEMENTARY TARIFF
CONSERVATION MARGIN TRACKER

APPLICABILITY

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

TEST PERIOD

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

RATE ADJUSTMENT

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

N

SPECIAL SUPPLEMENTARY TARIFF
CONSERVATION MARGIN TRACKER
(Continued

N

CONSERVATION MARGIN TRACKING BALANCING ACCOUNT

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

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

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

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

TIMING AND MANNER OF FILING

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

N

HELD FOR FUTURE USE D/N

RULE NO. 1

DEFINITIONS

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

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

RULE NO. 1

DEFINITIONS
(Continued)

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

RULE NO. 1

DEFINITIONS
(Continued)

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

RULE NO. 1

DEFINITIONS
(Continued)

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

L

RULE NO. 1

DEFINITIONS
(Continued)

Ownership:	The legal right of possession or proprietorship of the premise(s) where service is established. L
Peak Day:	Maximum daily consumption as determined by the best practical method available. L
Peak Irrigation Season:	The six-month period beginning April 1 and ending September 30.
Permanent Customer:	A customer who is a tenant or owner of a service location who applies for and receives natural gas service in a status other than transient, temporary or agent.
Permanent Service:	Natural gas service which, in the opinion of the Utility, is of a permanent and established character. The use of gas may be continuous, intermittent or seasonal in nature.
Person:	Any individual, partnership, corporation, governmental agency, or other organization operating as a single entity.
Plant Protection Gas:	Minimum natural gas volumes required to prevent physical harm to the plant facilities or danger to plant personnel when such protection cannot be afforded through the use of an alternate fuel. This includes the protection of such material in process as would otherwise be destroyed, but shall not include deliveries required to maintain plant production. For the purposes of this definition, propane and other gaseous fuels shall not be considered alternate fuels.
Point of Delivery:	The point where pipes owned, leased, or under license by a customer and which are subject to inspection by the appropriate city, county or state authority connect to the Utility's pipes or at the outlet side of the meter.

RULE NO. 1

DEFINITIONS
(Continued)

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

RULE NO. 1

DEFINITIONS
(Continued)

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

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C
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RULE NO. 1

DEFINITIONS
(Continued)

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

RULE NO. 1

DEFINITIONS
(Continued)

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

Rule No. 3

ESTABLISHMENT OF SERVICE

A. INFORMATION FROM APPLICANTS

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

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

   b. Identification that is acceptable to the Utility. T

   c. Service address or location and telephone number.

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

   e. Address where service was provided previously.

   f. Date applicant will be ready for service.

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

   h. Purpose for which service is to be used.

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

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

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

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

Rule No. 3

ESTABLISHMENT OF SERVICE
(Continued)

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

a. Residential *(Continued)*

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

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

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

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

b. Nonresidential

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

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

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

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

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

2. Reestablishment of Credit

a. Former Customers with an Outstanding Balance

Rule No. 3

ESTABLISHMENT OF SERVICE
(Continued)

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

3. Deposits *(Continued)*

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

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

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

c. Applicability to Unpaid Accounts

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

d. Refund of Deposits

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

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

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

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

Rule No. 3

ESTABLISHMENT OF SERVICE
(Continued)

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

1. Deposits *(Continued)*

a. Interest on Deposits

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

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

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

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

C. GROUNDS FOR REFUSAL OF SERVICE

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

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

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

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

Rule No. 3

ESTABLISHMENT OF SERVICE
(Continued)

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

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

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

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

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

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

2. Notification to Applicants or Customers

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

D. SERVICE ESTABLISHMENT, REESTABLISHMENT OR RECONNECTION

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

RULE NO. 9

BILLING AND COLLECTION
(Continued)

K. EQUAL PAYMENT PLAN

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

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

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

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

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

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

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

Current Tariff Sheets

TABLE OF CONTENTS

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

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

CURRENT TARIFF SHEET

Fifty-Eighth Revised A.C.C. Sheet No. 11
Canceling Fifty-Seventh Revised A.C.C. Sheet No. 11

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

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

Issued On August 18, 2004
Docket No. G-00000C-98-0568

Issued by
John P. Hester
Vice President

Effective August 27, 2004
Decision No. 62994

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

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

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

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

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

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

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

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

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

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

CURRENT TARIFF SHEET

Eighth Revised A.C.C. Sheet No. 14
Canceling Seventh Revised A.C.C. Sheet No. 14

STATEMENT OF RATES

EFFECTIVE TRANSPORTATION RATES APPLICABLE TO ARIZONA SCHEDULES 1/ 2/

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

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

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

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

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

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

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

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

Issued On April 22, 2004
Docket No. U-1551-96-0596

Issued by
John P. Hester
Vice President

Effective May 1, 2004
Decision No. 60352

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

CURRENT TARIFF SHEET

Third Revised A.C.C. Sheet No. 15
Canceling Second Revised A.C.C. Sheet No. 15

STATEMENT OF RATES
OTHER SERVICE CHARGES 1/

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

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

Issued On July 22, 2004
Docket No. G-01551A-02-0425

Issued by
John P. Hester
Vice President

Effective July 29, 2004
Decision No. 66101

Schedule No. G- 5

RESIDENTIAL GAS SERVICE

APPLICABILITY

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

TERRITORY

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

RATES

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

MINIMUM CHARGE

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

SPECIAL CONDITIONS

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

PURCHASED GAS ADJUSTMENT CLAUSE

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

RULES AND REGULATIONS

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

Schedule No. G-10

LOW INCOME RESIDENTIAL GAS SERVICE

APPLICABILITY

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

TERRITORY

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

RATES

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

MINIMUM CHARGE

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

SPECIAL CONDITIONS

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

Schedule No. G-10

LOW INCOME RESIDENTIAL GAS SERVICE
(Continued)

SPECIAL CONDITIONS *(Continued)*

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

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

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

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

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

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

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

PURCHASED GAS ADJUSTMENT CLAUSE

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

RULES AND REGULATIONS

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

Schedule No. G-15

SPECIAL RESIDENTIAL GAS SERVICE FOR AIR CONDITIONING

APPLICABILITY

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

TERRITORY

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

RATES

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

MINIMUM CHARGE

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

SPECIAL CONDITIONS

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

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

Schedule No. G-15

SPECIAL RESIDENTIAL GAS SERVICE
FOR AIR CONDITIONING
(Continued)

PURCHASED GAS ADJUSTMENT CLAUSE

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

RULES AND REGULATIONS

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

Schedule No. G-16

SPECIAL RESIDENTIAL GAS SERVICE FOR ELECTRIC GENERATION

APPLICABILITY

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

TERRITORY

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

RATES

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

MINIMUM CHARGE

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

SPECIAL CONDITIONS

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

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

Schedule No. G-16

SPECIAL RESIDENTIAL GAS SERVICE
FOR ELECTRIC GENERATION
(Continued)

PURCHASED GAS ADJUSTMENT CLAUSE

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

RULES AND REGULATIONS

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

Schedule No. G-25

GENERAL GAS SERVICE

APPLICABILITY

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

TERRITORY

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

RATES

1. Small and Medium General Gas Service

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

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

2. Large General Gas Service

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

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

Schedule No. G-30

OPTIONAL GAS SERVICE

APPLICABILITY

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

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

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

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

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

TERRITORY

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

RATES

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

Schedule No. G-35

GAS SERVICE TO ARMED FORCES

APPLICABILITY

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

TERRITORY

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

RATES

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

MINIMUM CHARGE

The minimum charge per month is the basic service charge.

SPECIAL CONDITIONS

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

PURCHASED GAS ADJUSTMENT CLAUSE

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

RULES AND REGULATIONS

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

Schedule No. G-40

AIR-CONDITIONING GAS SERVICE

APPLICABILITY

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

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

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

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

TERRITORY

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

RATES

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

MINIMUM CHARGE

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

Schedule No. G-45

STREET LIGHTING GAS SERVICE

APPLICABILITY

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

TERRITORY

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

RATES

Rate " X" – Lighting Only Service

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

Rate " Y" – Lighting in Combination With Other Usage

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

SPECIAL CONDITIONS

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

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

Schedule No. G-60

COGENERATION GAS SERVICE

APPLICABILITY

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

TERRITORY

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

RATES

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

MINIMUM CHARGE

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

SPECIAL CONDITIONS

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

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

Schedule No. G-60

COGENERATION GAS SERVICE
(Continued)

SPECIAL CONDITIONS *(Continued)*

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

PURCHASED GAS ADJUSTMENT CLAUSE

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

RULES AND REGULATIONS

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

Schedule No. G-75

SMALL ESSENTIAL AGRICULTURAL USER GAS SERVICE

APPLICABILITY

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

TERRITORY

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

RATES

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

MINIMUM CHARGE

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

SPECIAL CONDITIONS

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

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

Schedule No. R-1

RESIDENTIAL GAS SERVICE

APPLICABILITY

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

TERRITORY

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

RATES

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

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

MINIMUM CHARGE

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

SPECIAL CONDITIONS

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

PURCHASED GAS ADJUSTMENT PROVISION

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

RULES AND REGULATIONS

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

Schedule No. C-1

COMMERCIAL GAS SERVICE

APPLICABILITY

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

TERRITORY

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

RATES

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

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

SPECIAL CONDITIONS

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

PURCHASED GAS ADJUSTMENT PROVISION

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

RULES AND REGULATIONS

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

Schedule No. CRS-1

RESORT GAS SERVICE

APPLICABILITY

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

TERRITORY

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

RATES

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

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

SPECIAL CONDITIONS

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

PURCHASED GAS ADJUSTMENT PROVISION

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

RULES AND REGULATIONS

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

Schedule No. GAC-1

AIR-CONDITIONING GAS SERVICE

APPLICABILITY

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

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

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

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

TERRITORY

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

RATES

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

MINIMUM CHARGE

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

SPECIAL CONDITIONS

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

Schedule No. GAC-1

AIR-CONDITIONING GAS SERVICE
(Continued)

PURCHASED GAS ADJUSTMENT PROVISION

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

RULES AND REGULATIONS

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

Schedule No. CGEN-1

COGENERATION GAS SERVICE

APPLICABILITY

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

TERRITORY

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

RATES

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

MINIMUM CHARGE

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

SPECIAL CONDITIONS

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

PURCHASED GAS ADJUSTMENT PROVISION

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

RULES AND REGULATIONS

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

Schedule No. CNG-1

COMPRESSED NATURAL GAS SERVICE

APPLICABILITY

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

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

TERRITORY

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

RATES

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

MINIMUM CHARGE

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

SPECIAL CONDITIONS

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

PURCHASED GAS ADJUSTMENT PROVISION

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

RULES AND REGULATIONS

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

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

CURRENT TARIFF SHEET

Second Revised A.C.C. Sheet No. 47-50
Canceling First Revised A.C.C. Sheet No. 47-48

HELD FOR FUTURE USE

Issued On July 22, 2004
Docket No. G-01551A-02-0425

Issued by
John P. Hester
Vice President

Effective July 29, 2004
Decision No. 66101

Schedule No. T-1

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS

1. AVAILABILITY

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

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

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

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

2. APPLICABILITY AND CHARACTER OF SERVICE

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

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

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

Schedule No. T-1

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
(Continued)

3. RATES

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

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

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

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

Schedule No. T-1

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
(Continued)

3. RATES *(Continued)*

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

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

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

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

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

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

Schedule No. T-1

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
(Continued)

3. RATES *(Continued)*

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

4. MINIMUM CHARGE

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

5. FORCE MAJEURE

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

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

Schedule No. T-1

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
(Continued)

7. TRANSPORTATION IMBALANCE SERVICE *(Continued)*

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

7.2 Payment for Excess Imbalances

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

Schedule No. T-1

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
(Continued)

7. TRANSPORTATION IMBALANCE SERVICE *(Continued)*

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

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

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

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

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

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

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

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

WITNESSETH:

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

ARTICLE I - GAS TO BE TRANSPORTED

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

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

ARTICLE II - DELIVERY POINTS, PRESSURES AND QUANTITIES

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

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

ARTICLE III- APPLICABLE TRANSPORTATION RATES AND RATE SCHEDULE

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

ARTICLE IV - TERM OF AGREEMENT

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

ARTICLE V - NOTICES

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

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

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

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

ARTICLE VI - OTHER OPERATING PROVISIONS

A. TELEMETRY SIGNALS

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

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

B. CONFIDENTIALITY

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

C. OTHER PROVISIONS

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

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

ARTICLE VII - ADJUSTMENTS TO RULES AND REGULATIONS

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

ARTICLE VIII - PRIOR AGREEMENTS

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

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

ARTICLE IX - REGULATORY REQUIREMENTS

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

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

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

ARTICLE X - SUCCESSORS AND ASSIGNS

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

ARTICLE XI - RULES

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

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

EXHIBIT A

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

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

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

Date Issued:
Customer:

SOUTHWEST GAS CORPORATION "Utility" | ____________ "Customer"

By: ____________ By: ____________

Title: ____________ Title: ____________

Date: ____________ Date: ____________

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

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

WITNESSETH:

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

ARTICLE I – GAS TO BE TRANSPORTED

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

ARTICLE II – DELIVERY POINTS AND PROVISIONS OF SERVICE

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

ARTICLE III – APPLICABLE TRANSPORTATION RATES AND RATE SCHEDULE

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

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

ARTICLE IV – TERM OF AGREEMENT

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

ARTICLE V – NOTICES

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

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

ARTICLE VI – PRIOR AGREEMENTS

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

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

ARTICLE VII – REGULATORY REQUIREMENTS

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

ARTICLE VIII – SUCCESSORS AND ASSIGNS

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

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

SPECIAL SUPPLEMENTARY TARIFF
PURCHASED GAS COST ADJUSTMENT PROVISION

APPLICABILITY

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

CHANGE IN RATES

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

BANK BALANCE

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

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

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY SERVICES PROVISION

I. TITLE ASSIGNMENT SERVICE

A. APPLICABILITY

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

B. CHARACTER OF SERVICE

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

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

C. TERRITORY

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

D. TERM

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

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY SERVICES PROVISION
(Continued)

I. TITLE ASSIGNMENT SERVICE (Continued)

D. TERM *(Continued)*

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

E. RATES FOR TITLE ASSIGNMENT SERVICE

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

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

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

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

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

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

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY SERVICES PROVISION
(Continued)

I. TITLE ASSIGNMENT SERVICE (Continued)

F. CHANGES IN RATES

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

G. ACCOUNTING FOR TITLE ASSIGNMENT REVENUES

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

II. CAPACITY RELEASE SERVICE

A. APPLICABILITY

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

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

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

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY SERVICES PROVISION
(Continued)

II. CAPACITY RELEASE SERVICE (Continued)

A. APPLICABILITY (Continued)

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

B. RATES AND BIDDING PROCEDURES

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

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

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

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

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

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY SERVICES PROVISION
(Continued)

II. CAPACITY RELEASE SERVICE *(Continued)*

B. RATES AND BIDDING PROCEDURES *(Continued)*

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

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

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

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

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

c. Any remaining capacity available for release shall then be posted for open bidding to the applicable interstate pipeline electronic bulletin board at the minimum acceptable bid price determined according to Section B.2 above.

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY SERVICES PROVISION
(Continued)

II. CAPACITY RELEASE SERVICE *(Continued)*

B. RATES AND BIDDING PROCEDURES *(Continued)*

4. The Utility reserves the right to prearrange from time-to-time the release of excess capacity for a term of one month or less. Capacity released for a term of one month or less shall be subject to all FERC and interstate pipeline rules and regulations governing such releases, and shall be at rates greater than or equal to the minimum acceptable bid.

C. BILLING

Billing for released capacity shall be made by the interstate pipeline directly to acquiring customers and shippers. Shippers acquiring released capacity shall be billed by the pipeline at the accepted bid price plus applicable usage charges and surcharges. The Utility will receive credit from the interstate pipeline for the payment of reservation charges and reservation surcharges due from the acquiring shipper.

D. RECALL OF RELEASED CAPACITY

Capacity released by the Utility shall be recallable over the term of the release under the following conditions:

1. Force majeure situations occurring on the upstream pipeline system; or

2. To protect service to Priority 1 and Priority 2 customers; or

3. When the Utility's core demand for upstream pipeline capacity is greater than the Utility's current billing determinant or contract demand on the applicable interstate pipeline(s); or

4. If the acquiring shipper fails to remit payment for services rendered to the interstate pipeline when such amounts are due.

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY SERVICES PROVISION
(Continued)

II. CAPACITY RELEASE SERVICE (Continued)

E. ACCOUNTING FOR CAPACITY RELEASE CREDITS

All capacity release credits received by the Utility shall be credited to Account No. 191, Unrecovered Purchased Gas Costs.

HELD FOR FUTURE USE

RULE NO. 1

DEFINITIONS

For the purpose of these Tariffs, the terms and expressions listed below shall have the meanings set forth opposite:

Advance in Aid of Construction:	Funds provided to the Utility by an applicant for service under the terms of a main extension agreement, the amount of which may be refundable.
Alternate Fuel Capability:	A situation where an alternate fuel can be utilized whether or not the facilities for such use have actually been installed.
Applicant:	A person requesting the Utility to supply natural gas service.
Application:	A request to the Utility for natural gas service, as distinguished from an inquiry as to the availability or charges for such service.
Arizona Corporation Commission:	The regulatory authority of the State of Arizona having jurisdiction over the public service corporations operating in Arizona.
Average Month:	30.4 days.
Base Gas Supply:	Natural gas purchased by the Utility from its primary supplier.
Basic Service Charge:	A fixed amount a customer must pay the Utility for the availability of gas service, independent of consumption, as specified in the Utility's tariffs.
Billing Month:	The period between any two regular readings of the Utility's meters at intervals of approximately 30 days.
Billing Period:	The time interval between two consecutive meter readings that are taken for billing purposes.

RULE NO. 1

DEFINITIONS
(Continued)

Electronic Billing Service Provider:	An agent of the Utility that provides electronic bill presentment and payment service for the Utility and serves as a common link between the Utility and the customer.
Electronic Transfer:	Paperless exchange of data and/or funds.
Essential Agricultural Use:	Any use of natural gas which is certified by the Secretary of Agriculture as an "essential agricultural use."
Essential Industrial Process "process and Feedstock Uses:	Any use of natural gas by an industrial customer as gas" or as feedstock, or gas used for human comfort to protect health and hygiene in an industrial installation.
Excess Flow Valve:	A device designed to restrict the flow of gas in a customer's natural gas service line by automatically closing in the event of a service line break, thus mitigating the consequences of service line failures.
Expedited Service:	Service that is generally performed on the same workday the request for service is made. There may be instances where Company scheduling will not permit same day service; however, in no case will expedited service take longer than 24 hours from the time requested.
Farm Tap:	A service connection from a company distribution or transmission line operating at higher than normal distribution pressure, thereby requiring regulation and/or pressure limiting devices before the customer can be served.
Feedstock Gas:	Natural gas used as a raw material for its chemical properties in creating an end product.

RULE NO. 1

DEFINITIONS
(Continued)

Inability to Pay: Circumstances where a residential customer:

1. Is not gainfully employed and unable to pay, or
2. Qualifies for government welfare assistance, but has not begun to receive assistance on the date that he receives his bill and can obtain verification from the government welfare assistance agency, or
3. Has an annual income below the published federal poverty level and can produce evidence of this, and
4. Signs a declaration verifying that he meets one of the above criteria and is either elderly, handicapped, or suffers from an illness.

Industrial Boiler Fuel: Natural gas used in a boiler as a fuel for the generation of steam or electricity.

Industrial Customer: A customer who is engaged primarily in a process which creates or changes raw or unfinished materials into another form or product, including electric power generation.

Intra-day Nomination: A Nomination submitted after the nominating deadline for Daily and Standing Nominations specified in Section 6.1 of Schedule T-1 which has an effective time no earlier than the beginning of the next Gas Day, and which has an ending time no later than the end of that Gas Day.

RULE NO. 1

DEFINITIONS
(Continued)

Meter:	The instrument for measuring and recording the volume of natural gas that has passed through it.
Meter Tampering:	A situation where a meter or meter piping has been illegally altered. Common examples are meter bypassing and other unauthorized connections.
Minimum Charge:	The amount the customer must pay for the availability of gas service as specified in the Utility's tariffs.
Mobile Home:	A residential unit designed and built to be towed on its own chassis. It is without a permanent foundation and is designed for year-round living.
Monthly Operating Window:	A transportation operating constraint governing the allowable monthly difference between the customer's metered quantities and the sum of the customer's scheduled transportation quantities, plus any Utility-approved imbalance adjustment quantity. The Monthly Operating Window requires such difference to be within plus or minus 5 percent (±5%) of the month's total of daily scheduled transportation quantities, plus any Utility-approved imbalance adjustment quantity, or 1,500 therms, whichever is greater.
Mountain Clock Time (MCT):	Mountain Standard Time or Mountain Daylight Time, whichever is currently in effect in the majority of the Mountain Time Zone, regardless of which time the State of Arizona is operating under.
Off-Peak Irrigation Season:	The six-month period beginning October 1 and ending March 31.
Operating Day:	The 24-hour period beginning 7:00 a.m. Mountain Standard Time.
Ownership:	The legal right of possession or proprietorship of the premise(s) where service is established.
Peak Day:	Maximum daily consumption as determined by the best practical method available.

RULE NO. 1

DEFINITIONS
(Continued)

Peak Irrigation Season:	The six-month period beginning April 1 and ending September 30.
Permanent Customer:	A customer who is a tenant or owner of a service location who applies for and receives natural gas service in a status other than transient, temporary or agent.
Permanent Service:	Natural gas service which, in the opinion of the Utility, is of a permanent and established character. The use of gas may be continuous, intermittent or seasonal in nature.
Person:	Any individual, partnership, corporation, governmental agency, or other organization operating as a single entity.
Plant Protection Gas:	Minimum natural gas volumes required to prevent physical harm to the plant facilities or danger to plant personnel when such protection cannot be afforded through the use of an alternate fuel. This includes the protection of such material in process as would otherwise be destroyed, but shall not include deliveries required to maintain plant production. For the purposes of this definition, propane and other gaseous fuels shall not be considered alternate fuels.
Point of Delivery:	The point where pipes owned, leased, or under license by a customer and which are subject to inspection by the appropriate city, county or state authority connect to the Utility's pipes or at the outlet side of the meter.

RULE NO. 1

DEFINITIONS
(Continued)

Police Protection Uses:	Natural gas used by law enforcement agencies in the performance of their appointed duties.
Preemption of Gas Supply:	An emergency condition where the Utility may, under specified conditions, utilize the customer-owned gas supplies of low priority transportation customers to serve the requirements of higher priority transportation and sales customers.
Premises:	All of the real property and apparatus employed in a single enterprise on an integral parcel of land undivided by public streets, alleys or railways.
Process Gas:	Natural gas use for which alternate fuels are not technically feasible, such as in applications requiring precise temperature controls and precise flame characteristics. For the purpose of this definition, propane and other gaseous fuels shall not be considered alternate fuels.
Regular Working Hours:	Except for Utility observed holidays, the period from 8 a.m. to 5 p.m., Monday through Friday.
Residential Subdivision:	Any tract of land which has been divided into four or more contiguous lots for use for the construction of residential buildings or permanent mobile homes for either single or multiple occupancy.
Residential Use:	Service to customers using natural gas for domestic purposes such as space heating, air conditioning, water heating, cooking, clothes drying, and other residential uses and includes use in apartment buildings, mobile home parks, and other multi-unit residential buildings.

RULE NO. 1

DEFINITIONS
(Continued)

Service Line:	A natural gas pipe that transports gas from a common source of supply (normally a distribution main) to the customer's point of delivery.
Service Line Extension:	Consists of a service line provided for a new customer at a premise not heretofore served, in accordance with the service line extension rule.
Service Establishment Charge:	A charge as specified in the Utility's tariffs for establishing a new account.
Service Reconnect Charge:	A charge as specified in the Utility's tariffs which must be paid by the customer prior to reconnection of natural gas service each time the service is disconnected for nonpayment or whenever service is discontinued for failure to comply with the Utility's tariffs.
Service Reestablishment Charge:	A charge as specified in the Utility's tariffs for service at the same location where the same customer had ordered a service disconnection within the preceding 12-month period.
Shrinkage:	The cost of the gas volumes lost, unaccounted for, or used as company fuel in the transportation process and represented by the differential between the cost of gas on a sales basis and the cost of gas on a purchased basis.
Single Family Dwelling:	A house, an apartment, a mobile home permanently affixed to a lot, or any other permanent residential unit.
Southwest Vista:	An Electronic Bulletin Board service for subscribing users with computers and modems to dial up over telephone lines and access the many features available. The bulletin board is a communication tool that can support many users simultaneously.

RULE NO. 1

DEFINITIONS
(Continued)

Standard Delivery Pressure:	0.25 pounds per square inch gauge at the meter or point of delivery.
Standard Mantle:	A mantle which consumes a maximum of 2.6 cubic feet of gas per hour.
Standing Nomination:	A Daily Nomination which is effective for multiple Gas Days. Standing Nominations cannot exceed the term of the customer's Transportation Service Agreement. A Standing Nomination can be replaced by a new Daily Nomination or Intra-day Nomination; however, upon the expiration of such replacement Nomination, the Standing Nomination becomes effective again.
Storage Injection Gas:	Natural gas injected by a distributor into storage for later use.
Subdivision:	An area for single family dwellings which may be identified by filed subdivision plans.
Summer Season:	The six-month period beginning May 1 and ending October 31.
Supplemental Gas Supply:	Natural gas purchased by the Utility from all sources other than the base gas supply.
Supply Curtailment:	A condition occurring when the demand for natural gas exceeds the available supply of gas. This condition can occur due to supply failure or upstream pipeline capacity curtailment.
Tariffs:	The documents filed with and approved by the Commission which list the rules, regulations, services and products offered by the Utility and which set forth the terms and conditions and a schedule of the rates and charges for those services and products.
Tariff Sheets:	The individual sheets included in the tariff.

RULE NO. 1

DEFINITIONS
(Continued)

Utility's Operating Convenience:	This term refers to the utilization, under certain circumstances, of facilities or practices not ordinarily employed which contribute to the overall efficiency of the Utility's operations. It does not refer to customer convenience nor to the use of facilities or adoption of practices required to comply with applicable laws, ordinances, rules or regulations, or similar requirements of public authorities.
Weather Especially Dangerous to Health:	That period of time commencing with the scheduled termination date when the local weather forecast, as predicted by the National Oceanographic and Administration Service, indicates that the temperature will not exceed 32 degrees Fahrenheit for the next day's forecast. The Commission may determine that other weather conditions are especially dangerous to health as the need arises.
Winter Season:	The six-month period beginning November 1 and ending April 30.
Workday:	The time period between 8 a.m. and 5 p.m., Monday through Friday, excluding holidays.

RULE NO. 3

ESTABLISHMENT OF SERVICE

A. INFORMATION FROM APPLICANTS

1. The Utility may request the following minimum information from each new applicant for service:

   a. Name or names of applicant(s), including information regarding spouse and/or roommate(s).

   b. Driver's license or other acceptable identification.

   c. Service address or location and telephone number.

   d. Billing address or location and telephone number, if different than service address.

   e. Address where service was provided previously.

   f. Date applicant will be ready for service.

   g. Indication of whether premises have previously been supplied with the Utility's service.

   h. Purpose for which service is to be used.

   i. Indication of whether applicant is owner or tenant of or agent for the premises.

   j. Information concerning the natural gas usage and demand requirements of the customers so as to determine which tariff schedule is applicable.

   k. Type and kind of life-support equipment, if any, used by the customer.

   l. Third party notification. If an applicant or customer who is elderly and/or handicapped lists a third party whom they wish notified in the event that their service is scheduled for discontinuance in accordance with Rule No. 10, such third party's name, address and telephone number shall be noted on the application for service.

RULE NO. 3

ESTABLISHMENT OF SERVICE
(Continued)

B. ESTABLISHMENT AND REESTABLISHMENT OF CREDIT/DEPOSITS *(Continued)*

a. Residential *(Continued)*

(2) When credit cannot be established to the satisfaction of the Utility, the applicant will be required to:

(a) Pay the deposit amount billed by the date specified on the bill or make acceptable payment arrangements, or

(b) Place a deposit utilizing cash or an acceptable credit card to secure payment of bills for service as prescribed herein, or

(c) Provide a surety bond acceptable to the Utility in an amount equal to the required deposit.

b. Nonresidential

(1) The Utility shall not require a deposit from a new applicant for nonresidential service if the applicant has had service of a comparable nature within the preceding 24 months at another service location with Southwest Gas and a satisfactory payment history was established.

(2) When a deposit is required from a new applicant for nonresidential service, the applicant will be required to:

(a) Pay the deposit amount billed by the date specified on the bill or make acceptable payment arrangements, or

(b) Place a deposit utilizing cash or an acceptable credit card to secure payment of bills for service as prescribed herein, or

(c) Provide security acceptable to the Utility for payment to the Utility in an amount equal to the required deposit.

2. Reestablishment of Credit

a. Former Customers with an Outstanding Balance

RULE NO. 3

ESTABLISHMENT OF SERVICE
(Continued)

B. ESTABLISHMENT AND REESTABLISHMENT OF CREDIT/DEPOSITS *(Continued)*

3. Deposits *(Continued)*

(1) Residential customer deposits shall not exceed two times the customer's estimated average monthly bill.

(2) Nonresidential customer deposits shall not exceed two and one-half times the customer's estimated maximum monthly bill.

b. The Utility may bill the customer for any required deposit amount provided that credit and payment arrangements have been made according to the Utility's policy and procedures.

c. Applicability to Unpaid Accounts

Deposits and interest prescribed herein will be applied to unpaid bills owing to the Utility when service is discontinued.

d. Refunds of Deposits

(1) Upon discontinuance of service, the Utility will refund any balance of the deposit, plus applicable interest, in excess of unpaid bills. The Utility will return any credit balance by check to the last known customer address.

(2) After a residential customer has, for 12 consecutive months, paid all bills without being delinquent more than twice, the Utility shall refund the deposit with earned interest within 30 days.

(3) After a nonresidential customer has, for 24 consecutive months, paid all bills prior to the next regular billing, the Utility shall refund the deposit with earned interest within 30 days.

(4) In the case of refunding a deposit which has been made by an agency from the Utility Assistance Fund (Fund) established by A.R.S. 46-731 to provide assistance for eligible customers, such deposit shall be refunded to the Fund. The standard Rules and Regulations of the Utility as authorized by the Arizona Corporation Commission shall apply to these refunds.

RULE NO. 3

ESTABLISHMENT OF SERVICE
(Continued)

B. ESTABLISHMENT AND REESTABLISHMENT OF CREDIT/DEPOSITS *(Continued)*

3. Deposits *(Continued)*

e. Interest on Deposits

The Utility will pay 6 percent interest on deposits from the date of deposit until the date of settlement or withdrawal of deposit. Where such deposit remains for a period of one year or more and the person making the deposit continues to be a customer, the interest on the deposit at the end of the year shall be applied to the customer's account.

f. The Utility may review the customer's usage after service has been connected and adjust the deposit amount based upon the customer's actual usage.

g. A separate deposit may be required for each meter installed.

h. The Utility shall issue a non-negotiable receipt to the applicant for the deposit. The inability of the customer to produce such a receipt shall in no way impair his right to receive a refund of the deposit which is reflected on the Utility's records.

C. GROUNDS FOR REFUSAL OF SERVICE

1. The Utility may refuse to establish service if any of the following conditions exists:

a. The applicant has an outstanding amount due for the same class of service with the Utility and the applicant is unwilling to make satisfactory arrangements with the Utility for payment.

b. A condition exists which in the Utility's judgment is unsafe or hazardous to the applicant, the general population, or the Utility's personnel or facilities.

c. Refusal by the applicant to provide the Utility with a deposit when the customer has failed to meet the credit criteria for waiver of deposit requirements.

RULE NO. 3

ESTABLISHMENT OF SERVICE
(Continued)

C. GROUNDS FOR REFUSAL OF SERVICE (Continued)

d. Customer is known to be in violation of the Utility's tariffs filed with and approved by the Commission.

e. Failure of the customer to furnish such funds, service, equipment, and/or rights-of-way necessary to serve the customer and which have been specified by the Utility as a condition for providing service.

f. Applicant falsifies his or her identity for the purpose of obtaining service.

g. Where service has been discontinued for fraudulent use, in which case Rule No. 11 will apply.

h. If the intended use of the service is for any restricted apparatus or prohibited use.

2. Notification to Applicants or Customers

When an applicant or customer is refused service or service has been discontinued under the provisions of this rule, the Utility will notify the applicant or customer of the reasons for the refusal to serve and of the right of applicant or customer to appeal the Utility's decision to the Commission.

D. SERVICE ESTABLISHMENT, REESTABLISHMENT OR RECONNECTION

1. In order to partially cover the operating and clerical costs, the Utility shall collect a service charge whenever service is established, reestablished or reconnected as set forth and referred to as "Service Establishment Charge" in the currently effective Statement of Rates, A.C.C. Sheet No. 15 of this Arizona Gas Tariff. This charge will be applicable for (1) establishing a new account; (2) reestablishing service at the same location where the same customer had ordered a service disconnection; or (3) reconnecting service after having been discontinued for nonpayment of bills or for failure to otherwise comply with filed rules or tariff schedules.

RULE NO. 9

BILLING AND COLLECTION
(Continued)

K. EQUAL PAYMENT PLAN

1. The Equal Payment Plan (EPP) is available to all residential customers receiving (or applicants qualifying and applying to receive) natural gas service provided that the customer (applicant) has established credit to the satisfaction of the Utility.

2. Participation in the EPP is subject to approval by the Utility.

3. Customers may sign up for the EPP at any time of year. The EPP amount will be based on the annual estimated bill divided into 12 equal monthly payments.

4. The Utility will render its regular monthly billing statement showing both the amount for actual usage for the period and the designated EPP amount. The customer will pay his designated EPP amount, plus any additional amount shown on the bill for materials, parts, labor or other charges.

5. The settlement month will be the customer's anniversary date, 12 months from the time the customer entered the EPP. The settlement amount is the difference between the EPP payments made and the amount actually owing based on actual usage during the period the customer was billed under the EPP. All debit amounts are due and payable in the settlement month. However, debit amounts of $50 or less may be carried forward and added to the total annual estimated bill for the next EPP year. Credit amounts of $10 or less will be carried forward and applied against the first billing or billings due in the next EPP year. Credit amounts over $10 will be refunded by check.

6. The EPP amount may be adjusted quarterly to reduce the likelihood of an excessive debit or credit balance in the settlement month for changes in rates due to Commission-approved rate increases or decreases greater than 5 percent, or when estimates indicate that an overpayment or undercollection of $50 or more may occur by the end of the plan year.

7. The Utility may remove from the EPP and place on regular billing any customer who fails to make timely payments according to his EPP obligation. Such a customer will then be subject to termination of service in accordance with Rule No. 10 for nonpayment of a bill.