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ORIGINAL

Decision No. 86989

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of SOUTHWEST GAS CORPORATION For Authority to Increase Natural Gas Rates in San Bernardino County, California.	Application No. 55757 (Filed June 19, 1975)
Application of SOUTHWEST GAS CORPORATION For Authority to Increase Natural Gas Rates in Placer County, California.	Application No. 55789 (Filed July 3, 1975)

Constance L. Howard, Attorney at Law, for applicant.
James T. Quinn, Attorney at Law, and Vlado Bevc, for the Commission staff.

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O P I N I O N

Southwest Gas Corporation (SWG) seeks authority to increase gas rates in its San Bernardino County Districts (SBCD) and in its Placer County Districts (PCD). The original request in A.55757 (San Bernardino County) proposed an increase in gross revenues based on a 1976 test year at April 2, 1975 rate levels. The utility in A.55789 (Placer County) requested a gross revenue increase of $520,967, a 23.3 percent increase based on a 1976 estimated test year at April 1, 1975 rate levels.

The rate increase requests were revised in the course of public hearings, and applicant's final rate increase requests were for gross revenue increases of $1,850,458 for southern California (SBCD) and $509,717 for northern California (PCD).

These revenue increases are based upon applicant's revised 1976 estimates (as set forth in Table I and Table II adjusted for estimated conservation effects on revenues and expenses. We have set forth our conclusions on the requested adjustments for conservation effects separately.

The two applications were consolidated for public hearings. Applicant presented evidence of compliance with the notice requirements of Rule 24 and notice of hearings required by Rule 52 of our Rules of Practice and Procedure. Ten days of hearings were held commencing April 12, 1976 and concluding June 24, 1976 before Examiner Charles E. Mattson. The matter was submitted on concurrent reply briefs dated August 27, 1976.

At the public hearing held April 12, 1976 at Victorville, California, 14 members of the public appeared and advised the Commission regarding their concerns regarding the rate increase request. In our decision we have adopted lifeline rates in order to implement the policy of supplying essential quantities of gas to residential end users at January 1, 1976 rate levels for such lifeline quantities. Individuals who reside in mobilehome parks and apartments are also recognized as residential end users entitled to such protection. However, residential customers should be advised that outdoor gas lamps which burn 24 hours daily are not included within the end use entitled to a lifeline allowance. Such gas usage by residential users will consume quantities of gas which would otherwise be within the residential end use allowance.

SWG, a California corporation, distributes and sells natural gas in portions of San Bernardino County and Placer County as a public utility subject to this Commission's jurisdiction. SWG is also engaged in intrastate transmission, sale, and distribution of natural gas as a regulated public utility in portions of Nevada and Arizona. It is a natural gas company subject to the jurisdiction of the Federal Power Commission with respect to interstate transmission facilities and sales of natural gas for resale. SWG's principal office is at Las Vegas, Nevada, where centralized administrative and office functions are performed. In addition to the direct operating expenses incurred by both the northern and southern districts, it is necessary to apportion common expenses and plant items of the SWG systems for both the northern and southern districts in the State of California in order to calculate the revenue requirements of the separate districts.

Applicant's last general rate increase for the northern districts was granted by D.82714 in A.53747, a decision dated April 9, 1974. The rates granted were based upon an 8.75 percent rate of return. The last general rate case decision for the southern districts was D.84603 dated July 1, 1975 in A.54807. The rates granted were based upon a 9.20 percent rate of return.

In this decision we will review the evidence and our conclusions applicable to the revenue requirements for the southern districts and the northern districts separately. Certain of our conclusions will be applicable to both districts.

A. <u>Summary of Earnings - San Bernardino County Districts (SBCD)</u>

The differences between the staff and utility revised estimates are set forth in Table I, the summary of earnings for San Bernardino county. Our adopted results are set forth in the final column. The summary of earnings adopts rates in effect November 1, 1975. Table I does not incorporate the final revenue increase request of the applicant as set forth in Exhibit 33. That exhibit sets forth revised earnings based upon the impact of anticipated conservation on the operating revenues and expenses. The applicant's estimates as set forth in Exhibit 33 are dealt with separately in our discussion of conservation.

TABLE I

Summary of Earnings

Southwest Gas Corporation

San Bernardino County Districts

(Test Year 1976)

Item	Present Rates[1/] Staff Ex. 42 Table 11-A Col. (A)	Present Rates[1/] Utility Ex. 42 Table 11-A Col. (B)	Utility Proposed Rates Staff Ex. 42 Table 11-B Col. (A)	Utility Proposed Rates Utility Ex. 42 Table 11-B Col. (B)	Adopted Results at Present Rates
	(Dollars in Thousands)				
Operating Revenues	$11,169.6	$11,053.7	$12,955.3	$12,841.3	$11,151.3
Operating Expenses					
Cost of Purchased Gas	7,156.4	7,083.9	7,156.4	7,083.9	7,156.4
Operation & Maintenance	1,651.4	1,701.3	1,656.4	1,706.3	1,659.2
Administrative & General	584.8	606.0	602.0	623.3	598.7
Subtotal	9,392.6	9,391.2	9,414.8	9,413.5	9,414.3
Depreciation	629.0	625.9	629.0	625.9	625.9
Taxes Other Than Income	454.9	465.5	454.9	465.5	394.7
State Franchise Tax	2.7	.2	161.4	123.7	4.5
Federal Income Tax	(47.9)	.0	722.4	682.5	39.1
Total Operating Expenses	$10,431.3	$10,482.8	$11,382.5	$11,311.1	$10,400.3
Net Operating Revenues	$ 738.3	$ 570.9	$ 1,572.8	$ 1,530.2	$ 751.0
Rate Base	$14,212.3	$14,423.5	$14,212.3	$14,423.5	$14,423.5
Rate of Return	5.19%	3.96%	11.07%	10.61%	5.21%

(Red Figure)

1/ Rates in effect November 1, 1975. See Exhibits 37 and 42.

Our adopted results are based upon the following conclusions:

1. Operating Revenues

The differences between the staff and utility arise from different estimates of average annual usage and different assumptions regarding lifeline quantities. D.86087 dated July 13, 1976 in C.9988 sets forth lifeline volumes of gas by climatic zones. Our adopted results reflect lifeline quantities in accordance with that decision. The staff and the utility did not disagree as to the number of customers.

The different estimates of average annual use of the utility and the staff are set forth in Exhibit 38. The utility estimates of average annual use are based on a five-year trend for five separate classes of service. The staff's estimate was based on a trend using 12-month periods ending June and December of each year commencing with June 1971. Both the utility and the staff estimated 1976 usage based on temperature adjusted experience, but the staff trended 10 points and the utility used year-ended data for the five-year period. The staff accepted the utility estimate for the Big Bear interruptible customer.

The staff witness Fowler pointed out that the staff's 1976 estimates reflect average annual usage per residential customer at levels below 1975 adjusted experience. Witness Fowler felt this fact reflected the effect of conservation by the customers and did not recommend further adjustments of the estimates. For the reasons set forth in detail in our discussion of the conservation program we will not adjust the estimated sales figures for further conservation effects at this time. Our adopted sales figures are based upon the staff's estimated average annual usages.

2. Cost of Purchased Gas

The gas rates effective November 1, 1975 from applicant's suppliers were applied to the estimated annual sales plus unaccounted-for gas to obtain the estimated purchased gas expense. Our adopted calculation uses the 1975 average of 4.57 percent of purchased gas to calculate unaccounted-for gas. The rates authorized by our order in this case will necessarily include the effect of offset charges authorized subsequent to November 1, 1975.

3. Operation & Maintenance Expense (Other than Administrative & General)

The difference between the staff and the utility in operation and maintenance (O&M) expenses, excluding administrative and general (A&G) expense, are set forth in detail in Exhibit 37, revised Table 5-A. However, the final sales expense estimate of the staff was reduced from the $79,700 figure in Exhibit 37 to a total of $48,400. The sales expense estimates will be discussed separately. The total difference in O&M expense (excluding sales expense estimates) amounted to $19,200.

The staff and the utility treated the applicant's wage increase, effective May 1, 1976, differently. The wage increase negotiated with applicant's employees was 6.76 percent. The staff adjusted its estimated expenses to reflect a wage increase on an annual basis of 4.507 percent for 1976. The company reflected the full 6.76 percent increase for the entire year in its 1976 expenses. The treatment of the wage increase in the test year involves a choice between annualization of the increase for a full year (utility) or application of the increase as incurred in 1976 (staff).

We conclude that in applicant's case, the wage increase of 6.76 percent should be reflected in authorized rates for the full 1976 test year. The rates authorized herein will apply perspectively at a time when a 6.76 percent wage increase will be in effect. There is no evidence that the applicant has available proposed productivity gains which will reduce the impact of such increased labor costs. The staff's estimates of applicant's earnings indicate that, on the contrary, applicant's 1976 earnings levels are substantially below the authorized rate of return adopted for ratemaking purposes by D.84603 dated July 1, 1975.

Wage levels now in effect should be reflected for the entire test year in order to afford applicant an opportunity to achieve the authorized rate of return.

The staff witness estimated that (excluding sales expense estimates) the company's application of the wage increase for the entire year operates to increase the expense estimates of the staff approximately $12,000. The total O&M adopted expenses include this additional $12,000.

The remaining differences total $7,200 (less than one-half of one percent) and are a net figure of small differences spread throughout the O&M accounts. We have adopted the staff's estimates for these amounts (as set forth in the staff's revised Table 5-A, Exhibit 37). These staff estimates have been increased to reflect the wage increase for the full year.

4. <u>O&M - Sales Expenses (Account 911-913)</u>

In the course of the hearings both the utility and the staff revised their estimated sales expenses. The utility and the staff had originally used $2.66 per customer as the allowance for estimated 1976 sales expense. This amount was the amount authorized by D.84603 dated July 1, 1975. The sales expense estimates incorporated in O&M expense in Table I are $79,700 (staff) and $110,400 (utility), a difference of $30,700.

At hearing the staff reduced its original allowance for sales expense to $48,400. This staff recommendation was based upon five conservation programs set forth in Exhibit 29 with a total cost of $30,900 plus an additional allowance of $17,500 for additional manpower for the conservation programs.

The utility revised its estimate of 1976 sales expense from $110,700 (included in Table I) to a total of $125,288. This final estimate was based upon trended sales expenses of $69,768, an additional $40,664 for specific conservation programs, and $24,620 for additional manpower.

The utility and the staff agreed that 1976 sales expenses should include $30,900 for the conservation programs set forth in detail in Exhibit 29. In addition, the staff recommended an allowance of $17,500 for additional manpower to be devoted to the conservation effort. The utility requested a net allowance of $24,620 for such additional manpower.

The utility, however, claims that nonpromotional items, such as advice to customers, are included in the sales expense estimates. If so, such items must be separately set forth or reclassified to customer accounts. In fact, it appears that the utility has reclassified substantial amounts of sales expenses in 1974 and 1975. The staff witness testified that

$33,500 shown for "service" was in fact trended in other accounts since such expenditures were reclassified. Approximately $9,000 in promotional and institutional expenses claimed by the utility should be disallowed, since such expenditures are not borne by ratepayers. The utility claimed that $27,200 in its estimated sales expense is for conservation programs initiated by the utility. The staff recommends disallowance since the utility did not obtain a review of such programs and expenditures.

A disallowance of such expenditures at this time would be unreasonable since the utility management could not reasonably anticipate that it could make no conservation expenditures unless such expenditures were for conservation programs presented to and approved by the Commission staff. As recently as July 1, 1975 the utility was allowed amounts for sales expenses without specific restrictions.

At this time we will provide specific restrictions and advice to the utility. Promotional and institutional programs do not benefit ratepayers and should not be accounted for as sales expenses to be included as cost of service to ratepayers. Amounts which are claimed as allowable sales expense must be supported by specific evidence supporting inclusion as a proper cost of service. In the future all advertising expenditures charged to ratepayers will be supported by specific programs presented to the Commission staff or expenditures will not ordinarily be included in sales expenses charged to ratepayers.

Our specific 1976 test year allowances for sales expenses for SECD adopt the staff's recommendations, increased by the company's conservation expenditures of $27,200. In the future SWG's sales expenses will be allowed only if such expenditures are reasonable.

5. Administrative & General Expenses

The staff and utility differences on A&G expenses in Table I total $21,200 (3.6 percent). These differences arise from a variety of disputes regarding the detailed estimates as set forth in Exhibit 34, Table 6-A. Our determination regarding the differences are:

(a) Administrative & General Salaries (A-920). The staff applied the wage increase for two-thirds of the test year. For the reasons set forth in our earlier discussion, wage levels now in effect should be reflected for the full test year. The staff's estimate increased to reflect the present wage levels is $200,300. We have adopted the four-factor calculation as requested by the utility, including the number of employees in Factor III. The utility's estimate of $201,400 will be used.

(b) Office Supplies & Expenses (A-921). The record establishes that the staff properly excluded such items as country club dues, estimated at $12,300 from this account (before factoring). However, the staff also reduced this account by $38,200 on the basis that this reflected the amount reclassified to Account 932. This transfer was not reflected in revised Table 6-A in Account 932. Since we adopt the applicant's revised (and sharply reduced) estimate for Account 932, Account 921 should include the $38,200 amount before factoring. These changes result in a staff estimate of $123,200 and a utility estimate of $127,000. We adopt the staff's estimate. The failure to adjust out items such as country club dues in expense accounts presented in rate increase requests creates a serious doubt as to the validity of the applicant's estimate.

(c) Outside Services (A-923). The estimates differ by $1,800. Certain legal expenses were excluded by the staff in the development of its estimate. The utility estimate is below the prior two years' experience, and will be adopted as reasonable for the test year 1976. Separate items in this account may be nonrecurring but recent experience indicates the applicant's costs have not been declining.

(d) Property Insurance (A-924); Injuries & Damages (A-925). These accounts reflect sharply increased insurance costs to the utility. Applicant owns (through a subsidiary) 80 percent of the brokerage firm which places its insurance. The president of this firm (Don A. Harris & Associates, Inc.) is Don A. Harris. The brokerage firm was created very recently. The brokerage commissions paid by applicant are 7.5 percent on the primary liability insurance policy premium (a policy with a coverage of $100,000) and 9 percent on the excess umbrella policy premium (the excess coverage provides two layers with a total coverage of $4,900,000.

Because of the affiliated relationship, the applicant presented substantial additional evidence on the reasonableness of its insurance costs and its relationship to its insurance brokerage firms.

Don A. Harris testified as to his experience and background. He is an insurance broker with approximately 30 years experience in the insurance business. He presently holds a 20 percent interest in Don A. Harris & Associates, Inc. and is president of the firm. The firm operates an all lines insurance agency established September 1975. Prior to forming this firm he was vice president of Marsh & McLennan, Inc., an international insurance broker, at their Las Vegas office. He has placed liability insurance for applicant since 1966.

Robert L. Degner, executive vice president at Los Angeles and a corporate executive officer of Fred S. James & Co. of California, testified regarding insurance costs and broker's commissions. The record establishes that Mr. Degner is an expert in the insurance business and has been an insurance broker for approximately 25 years. He expressed the opinion that the brokerage fees paid to Don A. Harris & Associates, Inc. by applicant were below the average brokerage fees for the insurance policies placed by Mr. Harris on behalf of applicant.

Both Mr. Harris and Mr. Degner testified that the sharply increased insurance costs of applicant are not unusual under present conditions. Liability insurance has become substantially more costly in the last few years. It should be noted that Mr. Degner's opinion in this regard was based upon extensive experience in placing liability insurance policies for large companies, including utility companies larger than applicant.

On the record before us we find the insurance costs of applicant to be reasonable. However, the applicant should be advised that payments to an affiliate or subsidiary must be supported with substantial evidence that the transactions are reasonable.

Applicant's witness, Mr. Degner, suggested several ways to evaluate the reasonableness of its insurance costs. Insurance consultants may be available. Loss experience of a three-year period may be evaluated. An explanation of the consideration given to deductible features (self-assumption) and trade-offs available in this area should be examined by the applicant and explained on the record.

Applicant's sharply increased insurance costs for the past few years were supported by Mr. Degner's testimony. Mr. Degner testified as an independent expert and is not an employee of applicant. In the absence of evidence from an independent expert in the insurance field we might well have reached a different conclusion.

(e) Franchise Fee Requirements (A-927). The total amount in this account is derived from the franchise fee rates applied to operating revenues. The franchise fee rate is 0.963 percent of gross revenues and the difference in the estimates are related to estimates of operating revenues.

(f) Miscellaneous General Expenses (A-930); Rents (A-931). We adopt the staff's estimates for Accounts 930 and 931 as reasonable. The staff's estimates for the two accounts are $2,400 below the utility's.

The record is not entirely clear regarding the factors resulting in the different estimates. However, the staff found (and adjusted out) a number of items in A-930, including certain advertising expenditures. Ratepayers are not to be charged for expenditures made to promote the company image.

The balances in the accounts are assigned on a four-factor basis, and the estimated balances are adjusted for improper charges. It is difficult to determine how disputed amounts affect final estimates. For example, in 1974 the utility charged A-930 with $13,300 for fees paid the Commission. The utility argues that these fees are in connection with short-term financing authorized by D.82677. The cited decision deals with authorization for a stock issue and the related fees are $1,304. D.82680 dated April 2, 1974 involves authorization for $12 million in short-term notes with an associated fee of $12,000.

Since these fees relate to systemwide financial costs they should be apportioned between the various jurisdictions in which applicant operates. The fees related to a common stock issue should be reflected in Account 214 and not expensed.

As to the related fees for short-term debt, we agree with the applicant's position that such costs are difficult to charge to interest expense since there is no fixed amount of related long-term debt. Under such circumstances, we will accept the applicant's position that costs related to short-term debt may properly be reflected as current expense.

An effort to find the basis of the utility's estimate for A-931 is futile. Exhibit 2, Chapter 5, page 3, column (h), line 10 sets forth the estimated figure. The figure appears to be inconsistent with the amount used in column (e), line 10 on the same page, although the latter amount should be the basis of the factored estimate.

After reviewing the record we have adopted the staff's estimates for these accounts.

6. Depreciation Expense

The depreciation expense estimates of the staff and utility vary by approximately one-half of one percent. The staff estimates were prepared prior to the availability of the end-of-year balances in plant accounts for 1975. Under these circumstances we will adopt the utility's lower depreciation expense estimates.

7. Ad Valorem Taxes

The California State Board of Equalization establishes the assessed valuation of applicant's property subject to local property taxes by fiscal year commencing on July 1. Both the staff and the utility developed the estimated taxes for calendar year 1976 based on a review of taxes paid by past calendar years. For example, in 1975 recorded taxes paid of $59,419 for the northern districts are the actual tax assessments for fiscal years 1974 and 1975, divided by two. 1976 taxes are estimated by use of the net plant December 31 of the previous year, assessed valuation developed as the percentage of net plant, and the use of the tax rate per $100 assessed evaluation from the prior year.

The utility estimated 1976 ad valorem taxes as set forth in Exhibit 15, Chapter 6, pages 1 and 2, and Exhibit 2, Chapter 6, page 7. The tax rates from 1975 would be $7.80 (Placer County) and $11.38 (San Bernardino County).

The assessed valuations for Placer County by the California State Board of Equalization is set forth in Exhibit 15, Chapter 6, page 2, column (c). Commencing in 1968 the Placer County assessed valuations appear to show a four-year cycle in that the plant evaluation approximately doubles each fourth year. The increase every fourth year in the northern districts appears to be matched by decreases every fourth year in the southern districts (see Exhibit 2, Chapter 6, page 7, column (c)).

The fiscal year 1976-1977 assessed valuations became available in July 1976. The year 1976 is the fourth year of the cycle. The applicant states (by letter dated July 27, 1976) that the actual Board of Equalization assessed valuations reflect a reversal of allocations between northern and southern California for the current assessment period. The letter of the utility is not evidence, but the public records of the State of California Board of Equalization show that the actual assessed values of the Board for fiscal year 1976 are $1,436,450 (Placer County) and $3,463,830 (San Bernardino County).

There is no apparent reason to ignore the Board's actual valuations. The use of the 1976 actual valuations and the known 1975 tax rates should be used to derive the 1976 property taxes for each county. For calendar year 1976 the ad valorem taxes are $112,000 (Placer County) and $394,200 (San Bernardino County).

Obviously, there is an element of uncertainty in the future ad valorem tax assessed valuations as between the northern districts and southern districts. We will expect in any future rate proceeding that applicant will make some effort to determine the reason for the four-year cycle in order that we might make estimates of future ad valorem taxes based on more complete information than we have at this time.

8. Rate Base

The estimated weighted average rate base of the utility and the staff differ by a total of $211,200 (1.5 percent) for the San Bernardino County Districts. The major difference arises in estimated 1976 advances for construction. The staff witness stated that the staff's calculation should properly include the more recent data from 1975 (unavailable when the staff's initial estimate was made). The result of the use of the more recent data appears to remove any substantial difference in the final rate base estimates.

The staff witness testified that the staff's working capital estimates would substantially increase with the use of more recent data. Moreover, the applicant's witnesses stated that prepayments have been included in the working capital calculation for the regulated utility in the State of California in past rate proceedings.

Under the circumstances, it appears that the weighted average rate base of the applicant for San Bernardino County Districts is a reasonable estimate.

B. Summary of Earnings - Placer County Districts (PCD)

The utility revised its 1976 estimated results of operations for its northern California districts after 1975 results became available. Table II sets forth a comparison of the utility and the staff estimates at April 1, 1976 rate levels.

TABLE II

Summary of Earnings

Southwest Gas Corporation

Placer County Districts

(Test Year 1976)

Item	Present Rates[1/] Staff Ex. 43 Table 11-A Col. (A)	Present Rates[1/] Utility Ex. 43 Table 11-A Col. (B)	Utility Proposed Rates Staff Ex. 43 Table 11-B Col. (A)	Utility Proposed Rates Utility Ex. 43 Table 11-B Col. (B)	Adopted Results at Present Rates
	(Dollars in Thousands)				
Operating Revenues	$2,670.2	$2,574.8	$3,176.2	$3,046.3	$2,575.6
Operating Expenses					
Cost of Purchased Gas[2/]	1,394.1	1,331.8	1,394.1	1,331.8	1,339.0
Operation & Maintenance	284.8	301.7	289.5	306.1	286.9
Administrative & General	152.9	162.1	157.6	166.5	154.0
Subtotal	1,831.8	1,795.6	1,841.2	1,804.4	1,779.9
Depreciation	274.7	275.8	274.7	275.8	275.8
Taxes Other Than Income	58.9	59.8	58.9	59.8	112.0
State Franchise Tax	5.3	4.8	50.0	24.0	0.2
Federal Income Tax	1.8	.0	218.7	203.4	(41.7)
Total Operating Expenses	$2,172.5	$2,136.0	$2,443.5	$2,367.4	$2,126.2
Net Operating Revenues	$ 497.7	$ 438.8	$ 732.7	$ 678.9	$ 449.4
Adjustment to Rate Base	(5.6)	.0	(5.6)	.0	5.6[3/]
Net Operating Revenues Adjusted	492.1	438.8	727.1	678.9	455.0
Adjustment to Rate Base	(242.4)	.0	(242.4)	.0	(242.4)
Rate Base	$6,192.8	$6,317.5	$6,192.8	$6,317.5	$6,119.1
Adjusted Rate Base	$5,950.4	$6,317.5	$5,950.4	$6,317.5	$5,876.7
Rate of Return	8.27%	6.95%	12.22%	10.75%	7.74%

(Red Figure)

1/ Rates in effect April 1, 1976.

2/ Cost of gas at April 2, 1976 rates.

3/ Revenue adjustment.

As noted in our discussion regarding the San Bernardino County Districts, the utility presented a revised revenue request based on estimated conservation effects and this requested increase is reviewed in our discussion on conservation. The differences set forth in Table II are resolved as follows:

1. Operating Revenues

The differing revenue estimates of the staff and applicant result, in part, from differences in the estimated average annual usages for 1976. The utility trended temperature adjusted use for residential and general service customer classes for a five-year period ending December 1975. The staff adopted the average annual use for 1975 as its estimate for 1976. We have adopted the staff's use of trended data to reach 1976 estimate for the southern California districts. Consistent with that method we will adopt the utility estimates of average annual use derived by trending the last five years.

We have adopted the staff's estimate for the interruptible customers. The data on past interruptible usage is not temperature adjusted, and the utility estimate for 1976 is approximately 60 percent of the 1975 recorded and less than 50 percent of the average of the prior five years. The staff's use of the 1975 recorded usage reflects a sharp decline since 1971 and appears more reasonable than the continued sharp decrease estimated by the utility.

Our adoption of the utility estimated 1976 usage in average annual therms per customer is a determination which will affect our future evaluation of applicant's performance in the area of conservation. The use of the 1976 utility estimates as set forth on Exhibit 40 (with the exception of the interruptible customers) reflects the expectation that 1976 use per customer will drop below 1975 levels. As set forth in our discussion of required conservation programs, the applicant will be required to report on the progress and success of its conservation efforts. One measure of success would be to achieve temperature adjusted annual usages below the presently adopted utility estimates.

The 1976 test year revenues, as adopted, incorporate the lifeline allowances established by D.86087 dated July 13, 1976 in C.9988. Our findings on the necessary lifeline volumes of gas, by climatic zones, will be incorporated in our rate order in this case. The staff and the utility agreed that the estimate for uncollectibles should be based on the 1975 experience of the applicant company.

2. Cost of Purchased Gas

The adopted cost of purchased gas is based on the estimated sales. The allowance for lost and unaccounted for gas is based on actual 1975 experience. The rate levels for purchased gas are based upon the rates from applicant's suppliers as of April 2, 1976.

3. Operating & Maintenance Expense (Including Administrative & General)

The Operating & Maintenance (O&M) Expense estimates, as set forth in Table 2, differ by a total amount of $16,900 (5.9 percent). The differences are set forth by accounts in Exhibit 35, Tables 5-A and 5-B.

The staff and the utility analyzed certain of the accounts by separating nonlabor and labor costs. Differences in the application of a companywide wage increase in 1976 resulted in total O&M differences of $12,000 in the southern districts of applicant. Consistent with our conclusion for the southern districts that 1976 test year estimates should reflect wage levels now in effect for an entire test year, the staff's estimated labor costs in the accounts should be increased for such full-year effect of the wage increase.

The O&M accounts are set forth separately in Tables 5-A and 5-B in Exhibit 35. The nonlabor and labor costs are not separately stated for each account. The applicant trended the nonlabor expense separately to develop estimates for 1976, and adjusted the wage level elements to reflect an estimated 6 percent wage increase for 1976. The staff applied the May 1, 1976 wage increase as incurred (approximately a 4½ percent increase). The staff accepted certain of applicant's estimates on some accounts and rejected the applicant's estimates for others.

The evidence in the record is not sufficiently detailed to evaluate specific differences account by account. The staff argues that the applicant's trending of recorded data makes no allowance for nonrecurring items, and results in the inclusion of improper items. The staff points out the inclusion of costs for a new logo, certain advertising costs, and country club dues are improperly included in expense accounts.

The utility argues that its estimates are more reliable, based on a comparison of past estimates of the staff and the utility. Both the staff and the utility urge acceptance of their respective estimates more on subjective grounds rather than on specific objective data applicable to separate accounts.

An examination of the entire record discloses the difficulty of estimating expense levels under recent economic conditions. The original staff and utility O&M estimates for 1976 were $237,500 (the staff) and $280,300 (utility), a difference of $42,800. The revised 1976 estimates, after 1975 recorded data became available, became $284,800 (staff) and $301,700 (utility), a $16,900 difference. The staff's revised estimate for 1976 increased approximately 20 percent over its earlier estimate, reflecting sharp inflation experienced in 1975. The revised estimates for A&G expenses reflect an increase of approximately 10 percent above the staff's earlier estimate.

The adopted figures include uncollectibles (A-904) and franchise fees (A-927) calculated from adopted revenues at the agreed upon rates. We have adopted the staff recommended O&M expenses as revised, with an increase of $3,100 in the staff estimates as an allowance for labor costs at present wage levels and to include A-813. The A&G expense estimates of the staff, increased by $2,000 to reflect increased wage levels, are adopted.

The sales expense allowance Accounts 911-913 will be reflected in the total amount of $15,800. This amount is specifically authorized for the conservation programs set forth in Exhibit 30, the programs specifically recommended by the staff after review of the conservation unit.

We have adopted the O&M expenses as set forth by the staff in Exhibit 35, Table 5-A and Table 5-B, adjusted as follows: (1) uncollectibles on estimated revenues are $12,900; (2) sales expense is included at $15,800 for the conservation programs specifically set forth in Exhibit 30; (3) the O&M expenses are increased to include other gas supply expenses (A-813) in the amount of $1,100; (4) the adjusted O&M estimates of the staff have been increased $2,000 in order to reflect wage costs at the present wage levels for the entire year 1976; and (5) the adjusted O&M expense is $286,900.

We have adopted the staff's estimated A&G expenses as set forth in Exhibit 35, Table 6-A with the following adjustments: (a) the franchise fee expense included in A-927 is calculated on the estimated revenues as $24,000; (b) we have increased the total A&G expense estimate by $2,000 to reflect the impact of the wage rates now in effect for the entire year; and (c) the final adjusted A&G estimate is $154,000.

These adopted operating expenses are subject to one final adjustment. The staff has set forth in Exhibit 36 the adjustment to rate base to reflect a downward adjustment to applicant's plant based upon work performed for applicant in the past by then associated companies. The adjustment involves a reduction in rate base and an associated negative expense adjustment. By D.82714 dated April 9, 1974 in A.53747 we found the associated rate base adjustment was $273,300 and the negative expense adjustment was $5,300.

In this proceeding the staff, by Exhibit 36, calculated the net reduction to rate base for the 1976 test year, based on composite depreciation rates, at $242,400. The associated expense adjustment is a reduction in expenses of $5,600. As the staff witness testified, this adjustment to rate base shown in the summary of earnings table as a negative $5,600 may be reflected as an increase to operating revenues. The adjustment to rate base is a negative $242,400 as set forth in Table 2. The staff's ratemaking adjustments as set forth in Exhibit 36 are adopted.

4. Rate Base

The rate base estimates of the staff and utility for Placer County are set forth in detail in Exhibit 35, Table 10-A. As noted above, the applicant failed to adjust its rate base in accordance with D.82714 dated April 9, 1974.

The staff's working cash calculation should reflect the staff's updated expenses in purchased gas estimates, resulting in a working cash estimate of $186,908. The utility's revised gas plant in-service figure reflects the actual December 31, 1975 amounts. This figure should be reduced by $13,800 to reflect the staff's disallowance of inoperable distribution mains pursuant to D.82714 (Exhibit 25, page 8-1, paragraph 2(d)).

Since applicant conducts its utility operations in three separate states, California, Nevada, and Arizona, it is necessary to allocate common plant among its districts. Company headquarters are located at Las Vegas, Nevada, and common utility plant used by the utility in its operations cannot be directly assigned to one department or division. Four factors have been used to allocate common plant (including associated depreciation) and certain administrative and general expenses to the separate districts of applicant. Allocations are also involved in calculation of income taxes and income deductions.

The applicant requested that the cost of purchased gas be excluded from factor one, the direct operating expenses less uncollectibles. The applicant's request that the cost of purchased gas be excluded from the calculation is a change from the traditional calculation of this factor. Applicant contends that the cost of purchased gas has become an unpredictable and unstable variable due to frequent and substantial price changes and curtailment of supply.

The staff witness Barrett stated that the cost of purchased gas should not be included in the factor because the cost of gas is not an item which fluctuates on the basis of what a management employee might do. He excluded the cost of purchased gas in his calculation of the four-factor allocation because he felt it was not a true measure of variable cost. The staff witness for Finance and Accounts recommended continued inclusion of the cost of purchased gas on the grounds that it is a very important cost component and the calculation should be consistent with prior years.

We agree with the basic contention that the factors should be calculated on a consistent basis from case to case unless substantial grounds are presented for changing the method of calculating allocations. However, based on the reasons advanced by the staff witness Barrett, we will exclude the cost of purchased gas from the four-factor allocation.

The utility calculated the third factor by using the number of employees on direct payroll. The staff calculation of factor three used the amount of direct payroll, not the number of employees. We will continue to use the number of employees since this is the established method of calculating this factor. The record does not disclose any reason to change the method of calculating this factor.

Prepayments should be allocated to working capital as claimed by the applicant. The inclusion of prepayments is consistent with our past treatment of this item.

We will adopt the staff's rate base estimates as set forth in Exhibit 35, Table 10-A, with the following exceptions and adjustments: adopt utility figures from Exhibit 35, Table 10-A, as follows: Weighted Avg. Net Additions, 48.9; Allocated Common Plant, 145.0; Avg. Allocated Net Additions, 0.2; Prepayments, 8.7; Depreciation Reserve, 1,552.8; and System Allocated Reserve, 10.3. The gas plant in service on December 31, 1975 is $8,042,300, which reflects that gas plant in service on December 31, 1975 reduced by $13,800, the adjustment set forth above. Working capital includes the staff's M&S estimate, and working cash is recalculated on the adopted O&M expenses pursuant to the method recommended by the staff witness. The adopted total net working capital figure is $221,600.

As a result of the adjustment to working capital and utility plant, the weighted average depreciated rate base is $6,119,100. This rate base is reduced by the $242,400 adjustment described above.

C. Rate of Return

The applicant presented testimony of its Senior Vice President, Finance and Accounts, in support of a requested rate of return of 10.4 percent. The staff presented the testimony of a financial examiner from the Finance and Accounts Division in support of a recommended rate of return of 9.5 to 9.8 percent.

The assumed capital structures in associated capital costs and allowances are as follows:

TABLE III

Capitalization and Annual Costs
December 31, 1976

Component	Utility1/			Staff2/		
	Capital Ratio	Cost	Weight	Capital Ratio	Cost	Weight
Long-Term Debt	55.7	7.84	4.37	55.49	7.91	4.39
Preferred Stock	12.9	8.69	1.12	12.83	8.99	1.15
Common Stock Equity	31.4	15.64 3/	4.91	31.68	13.30 3/	4.21
Totals	100.0		10.40	100.00		9.75 4/

1/ Exhibit 2.c.9, pages 2, 4, Transcript page 266.

2/ Exhibit 10, Table 10.

3/ Calculated equity allowances.

4/ The staff recommended range is 9.50 percent to 9.80 percent.

As Table III discloses, the rate of return differences are almost entirely attributable to differences in the allowance for common equity. An assumed allowance for common equity of 13.3 percent produces rate of return allowances of 9.67 percent (utility) and 9.75 percent (staff).

We adopt the staff's capital ratios and debt and preferred stock costs. We agree with the staff's view that cumulative convertible preferred stock should be considered as part of common stock equity. Moreover, the staff's debt and preferred stock allowances recognized the increased capital costs recently incurred by the utility. The remaining question is the proper allowance for common stock equity.

The utility's requested 10.4 percent rate of return is based on a 16 percent allowance for common equity capital. The staff's recommended common equity allowance ranges from 12.50 percent to 13.5 percent and the related range for rate of return is 9.5 percent to 9.8 percent.

We have recently reviewed the rate of return requirements for applicant's San Bernardino county operations for test year 1975 in D.84603 dated July 1, 1975. That decision adopted a 9.2 percent rate of return as reasonable and the related return on common equity was 12.79 percent. Based on the estimated capital costs that 9.2 percent rate of return would have provided a times interest coverage of 2.48 for long-term debt and a combined coverage factor for all interest and preferred stock dividends of 1.90 times.

Applicant's 1976 capital structure differs substantially from our 1975 estimates. The cost of long-term debt and preferred stock has increased and the common equity component in the capital ratio has decreased. An allowance of 12.79 percent on common equity capital would now require a rate of return of 9.59 percent while providing interest coverage of 2.18 for long-term debt.

The applicant advances two arguments in support of its requested 16 percent allowance on common equity capital. The higher return would enable the utility to use greater amounts of internally generated capital to finance new construction. Applicant alleges that internally generated capital is cheaper than equity capital financing. The second argument of applicant is that the capital structure has changed substantially and substantial increases have been made in the equity portion and decreases in the debt portion. Outside long-term financing has been difficult, and applicant has new construction obligations.

We cannot accept applicant's assumption that the allowance for common equity should be increased by 25 percent from 1975 to 1976. An increase of such magnitude would, in effect, put the entire burden of increasing capital costs and a reduced common equity component on the ratepayers. Moreover, such a generous allowance would burden the ratepayers with an obligation to support new construction with excessive amounts of internally generated capital. The established policy of this Commission is to recognize the absolute necessity of promoting conservation, not to encourage increased growth.

The applicant has elected to retain the benefits of additional ITC created by the 1975 federal tax reduction act by use of ratable flow-through. This election has obvious advantages to the utility and results in higher costs to the ratepayers than the full flow-through option. We have, for the reasons set forth in our discussion of ITC, accepted ratable flow-through as requested by applicant. Having retained the benefits of its ITC election, applicant is not entitled to a generous rate of return.

However, we do recognize that applicant is a small gas distributor and that its securities are generally regarded as lower medium grade investments by the financial community (below Baa). We further acknowledge that applicant has experienced difficulty in obtaining long-term financing and that an increase in the allowance for common equity is required to maintain adequate interest and dividend coverage for applicant's senior securities and to support future financing for new facilities needed to serve its customers.

Under the circumstances, we conclude that a rate of return of 9.75 percent is reasonable. This return reflects a sharp increase from the 9.2 percent return authorized for the prior year and reflects the increased cost of capital, including an increase in the allowance for common equity to 13.3 percent. Based on adopted capital costs a return of 9.75 percent will provide times interest coverage of 2.22 for long-term debt and combined coverage of 1.76 for all interest and preferred stock dividends. Our adopted rate of return takes into account both the conservation programs required by this decision and our treatment of the investment tax credit (ITC) available to the applicant.

D. Net-to-Gross Multipliers

For the southern California districts of Southwest Gas Corporation, a proposed change of $1,000 in net revenue requires a change of $2,144 in gross revenues. This factor is based upon uncollectibles at 0.47 percent, franchise taxes at .963 percent, California corporate franchise tax at 9 percent, and federal income tax at 48 percent. The resultant multiplier is 2.144.

For the northern California districts the franchise tax factor is 0.933 percent and uncollectibles are 0.5 percent. These changes balance out and the net-to-gross multiplier for the northern districts is identical to the factor in the southern districts.

E. Conservation

In the course of the hearings the applicant presented its final revenue increase request based upon adjustments for conservation. Applicant's proposed adjustment for conservation was a reduction of operating revenues to reflect reduced sales after assumed customer conservation, adjustment of operating expenses to reflect the reduced cost of purchased gas and associated changes in uncollectibles and franchise taxes, and increased sales expense amounts required to finance the conservation programs. The effect of these adjustments resulted in a proposed gross revenue increase for the southern California districts in the total amount of $1,850,458, an increase of $62,583 over the revised request. The result of similar adjustments for the northern California districts resulted in a final gross revenue increase request of $509,717.

Applicant's witnesses argued that a failure to adjust estimated operating revenues for conservation, as applicant requests, could only be justified on the assumption that the approved conservation programs set forth in Exhibits 29 and 30 would fail to achieve customer conservation of gas usage.

Exhibit 29 sets forth the specific programs which are recommended by the staff of the southern California districts. The total utility's cost for the five programs is $30,900, before an allowance for additional manpower. Applicant is directed to implement these energy conservation programs at once. Moreover, applicant will be required to report annually on the progress of the programs instituted pursuant to Exhibit 29. In view of the declining supply of natural gas, applicant will be expected to aggressively pursue conservation programs. Energy conservation programs for the northern California districts as set forth in Exhibit 30 will be implemented by the applicant.

Applicant desires rates to be established on the basis of the assumed success of future conservation programs.

We will recognize the effect of energy conservation programs on gas sales and revenues as soon as the applicant clearly demonstrates that such effects are taking place.

F. Investment Tax Credit (1975 Options)

Prior to the Tax Reduction Act of 1975 (TRA) the applicant had elected to flow through accelerated depreciation and investment tax credits (ITC) for both tax and cost-of-service purposes. The 1975 Act increased the ITC allowances from 4 percent and 7 percent levels to 10 percent. Under the provisions of the 1975 Act utilities were authorized to make an election to flow through the full benefit of the additional tax credits authorized by the 1975 Act.

The applicant did not make an election to flow through the additional credits, but selected another option. The utility elected to flow through the credit to income (as a reduction of cost-of-service) no faster than ratably over the life of the property (35 years). The 1975 Act provides that if a regulatory agency requires a faster flow-through or adjusts rate base in excess of the ratable amounts, the additional ITC will be disallowed.

The result of the election of the applicant and the provisions of federal law result in a situation where the tax as actually paid by the applicant reflects the tax credits in the full amount of 10 percent, but the tax as computed for purposes of establishing rates reflects the 1975 additional ITC on a ratable flow-through basis. The tax credit for ratemaking purposes is computed by a 35-year amortization of the amount of excess investment tax credit used to reduce the taxes actually paid. In short, the ratepayers are charged for taxes that are not in fact paid in the test year.

Exhibit 23 sets forth the effect of this tax computation in terms of charges incurred by ratepayers for the year ending December 31, 1975. The staff and the utility have in the past amortized the investment tax credit over a five-year period. This treatment is continued for the investment tax credit available prior to the 1975 Act. For the year ended December 31, 1975 such tax credits total $52,126 (total California) and are flowed through over a five-year period at a rate of $10,424 annually. The additional ITC created by the 1975 Act totals $62,608 and for year ending December 31, 1975 applicant proposes to flow through $1,788 of this amount based on the 35-year amortization.

The benefit to the applicant company and the cost to the ratepayers is obvious. For the year 1975 applicant receives approximately $61,000 of tax credits representing taxes charged the ratepayers as a cost-of-service but not actually paid the IRS. The gross revenue requirement increases approximately $130,400 for the year 1975. The applicant argues that its election of the additional ITC provided by the 1975 Act was justified because of its capital requirements and financial condition at the time it exercised the option. The option exercised created the maximum benefit for the ownership interest of the utility at the maximum cost to the ratepayers. The only benefit to the ratepayers on the option exercised is that the utility has secured a financial advantage when contrasted with full flow-through companies which lowers its risk of doing business. The utility has improved its financial position as a result of the large cash flow immediately available. The ratepayers can realize such benefit only when the reduced risk is given consideration in an authorized rate of return.

The magnitude of the company's financial gains in any given year can be measured by the 12 months ended December 31, 1975. The financial impact described above related to the total California operations only. For the 12 months ending 1975 the total company ITC generated is $541,018, including the additional ITC from the 1975 tax act. Approximately $53,500 of total investment tax credit will be amortized over a five-year period and the balance will be amortized over a 35-year period as set forth on Exhibit 23. Stated another way, the total tax credits of $541,018 for the year ended December 31, 1975 will operate to reduce taxes actually paid, but applicant will apply tax credits of $24,422 for ratemaking purposes for that year. The financial advantages to applicant on a total company basis amount to a gain of $500,000 in tax liability charged to the ratepayer but retained by the utility and amortized for 35 years under flow-through to ratepayers.

The company urges that the California Commission should accept its treatment of the investment tax credits from the 1975 Act because both of the other State jurisdictions--Nevada and Arizona--have already accepted such treatment for tax purposes and for ratemaking purposes and to require a faster flow-through or a rate base adjustment would result in a disallowance by the IRS of all of the additional credits. Exhibit 23 sets forth the additional investment tax credit from the 1975 Act in the total amount of $273,466, including the total California excess or additional amount of $62,608.

Consistent with our treatment of this problem in D.86595 dated November 2, 1976 in A.55345 (mimeo. page 61), the five-year averaging method on classes of plant agreed to by the utility and the staff is reasonable for the test year. We will recognize ratable flow-through for the additional ITC in computing the utility's FIT. The advantages to the company have been considered in our determination of the reasonable rate of return. We do not adopt a rate base adjustment related to the ITC.

G. Purchased Gas Adjustment

In our earlier decision we have authorized a purchased gas adjustment to be included in the tariffs for applicant for service in San Bernardino county. The staff and the applicant have no disagreement with the proposition that the tariffs for natural gas service in Placer County should contain a similar purchased gas adjustment, in order to reflect changes in the cost of purchased gas in rates and charges to its ratepayers. Our decision herein shall adopt a purchased gas adjustment to be filed for all service in the State of California.

H. Rates

D.86087 dated July 13, 1976 in C.9988 established lifeline volumes for residential users of gas. Applicant was a respondent in C.9988 and must comply with the provisions of D.86087. Rate increases authorized by this decision will not be applicable to lifeline sales.

In view of the end-use allowances now applicable to lifeline customers and the necessity of establishing lifeline and non-lifeline catagories of customers, certain tariff provisions may be eliminated. The residential heat only rate in southern California will be eliminated. The G-12 rate in northern California is eliminated and the G-10 rate will be the general service residential rate.

The service establishment charge for all areas will be $10 (regular) and $18 (after hours). The non-lifeline rates will be increased by authorization of a single rate block per therm or an equivalent rate for all usage for each territory served. Prior lifeline rate differences continue, to the extent that differentials exist in non-lifeline rates they are the result of historical cost differences between territories served.

Findings

1. By A.55757 Southwest Gas Corporation requests authority to increase rates and charges in its San Bernardino County Districts by $1,850,458 (17 percent). This request is based on revised estimates for test year 1976, including conservation assumptions.

2. By A.55789 Southwest Gas Corporation requests authority to increase rates and charges in its Placer County Districts by $509,717 (20 percent). This request is based on revised estimates for test year 1976, including conservation assumptions.

3. The adopted (1976) estimates set forth in the summary of earnings in Table I are reasonable estimates of applicant's 1976 operations for its San Bernardino County Districts.

4. The adopted 1976 estimates set forth in the summary of earnings in Table II are reasonable estimates of applicant's 1976 operations for its Placer County Districts.

5. The staff's 1976 estimates for applicant's operations are set forth in Table I (San Bernardino County) and Table II (Placer County). Based on staff's estimates set forth in said tables, gross revenue increases to produce a 9.75 percent rate of return would be $1,388,000 (12.4 percent) for San Bernardino County and $188,900 (7 percent) for Placer County.

6. The applicant requests increased rates and charges based upon a return of 10.4 percent. The staff recommends that a rate of return of 9.50 to 9.80 percent be authorized. For the reasons set forth in our decision, rate increases will be authorized based upon an adopted rate of return of 9.75 percent. This adopted rate of return will produce coverages of 2.22 times long-term debt interest and 1.76 times for all interest and preferred stock dividends.

7. The rate increases requested by applicant are excessive. Based on our adopted 1976 estimates, gross revenue increases of $1,405,600 (12.6 percent) for the San Bernardino County Districts and $249,400 (9.7 percent) for the Placer County Districts should be authorized in order to produce a 9.75 percent rate of return.

8. Applicant must comply with all applicable provisions of our first interim order in C.9988 (D.86087 dated July 13, 1976). Rates and charges for lifeline service established pursuant to that decision should not be changed at this time. All non-lifeline gas will be priced at substantially one rate per therm (or equivalent) and all other non-lifeline rate blocks should be eliminated for each territory served.

The service establishment charge should be $10 (regular) and $18 (after hours) for all areas.

9. Applicant has filed a purchased gas adjustment tariff applicable to its San Bernardino County rate schedules. Applicant should be authorized to file a purchased gas adjustment (PGA) applicable to its Placer County rate schedules. Such PGA should contain substantially the same conditions as the PGA now on file, including the condition that no change in rates under the PGA clause will become effective without Commission approval.

10. Conservation of energy resources is in the public interest. Applicant should be required to promote conservation as follows:

(a) Applicant should implement the conservation programs set forth in Exhibits 29 and 30 and additional manpower should be used to promote the conservation programs.

(b) Applicant should report annually to the Commission on the progress of its programs.

(c) Applicant estimates that the conservation program will reduce sales, and alleges that rate increases of approximately $100,000 will be required to offset the revenue loss from such reduced sales.

(d) We will recognize the effect of energy conservation programs on gas sales and revenues as soon as the applicant clearly demonstrates that such effects are taking place.

The Commission concludes that the application should be granted to the extent set forth in the following order and in all other respects denied.

<u>O R D E R</u>

IT IS ORDERED that:

1. Southwest Gas Corporation is authorized to file the revised rate schedules attached to this order as Appendix A. Appendix A provides revised rates for San Bernardino County only. Such filing shall comply with General Order No. 96-Series. The effective date of the revised schedules shall be one day after the date of filing. The revised schedules shall apply only to service rendered on and after the effective date of the revised schedules.

2. Southwest Gas Corporation is authorized to file the revised rate schedules attached to this order as Appendix B. Appendix B provides revised rates for Placer County only. Such filing shall comply with General Order No. 96-Series. The effective date of the revised schedules shall be one day after the date of filing. The revised schedules shall apply only to service rendered on and after the effective date of the revised schedules.

3. Southwest Gas Corporation shall:

(a) Vigorously pursue the conservation programs found necessary by this decision.

(b) Report in detail on the progress of its conservation programs to the Commission as part of the reporting mechanism in C.9884.

(c) Southwest Gas Corporation is again placed on notice that the Commission will monitor the continuing effectiveness of its energy conservation efforts and will evaluate the utility's vigor and imagination in implementing and expanding its energy conservation programs when deciding upon a fair rate of return in future rate cases.

4. Southwest Gas Corporation is authorized to file a purchased gas adjustment (PGA) clause applicable to its Placer County Districts. Such PGA shall contain conditions similar to the conditions now applicable to the San Bernardino County PGA now on file.

The effective date of this order shall be twenty days after the date hereof.

Dated at San Francisco, California, this 23rd day of FEBRUARY, 1977.

Robert Batinovich
President

Leonard Ross

Richard D. Gravelle
Commissioners

I concur but must indicate that the rate of return allowed herein seems to me to be more than generous considering the managerial choices made by this company
Richard D. Gravelle
Leonard Ross

Commissioner William Symons, Jr., being necessarily absent, did not participate in the disposition of this proceeding.

Commissioner Vernon L. Sturgeon, being necessarily absent, did not participate in the disposition of this proceeding.

APPENDIX A

RATES - Southern California Division

	G-1 Lifeline	G-1 Non-Lifeline
Mo. Charge	$3.383	$3.383
First 32 therms	0.20911	0.27409
Next 72 therms	0.19826	0.27409
Next 2 therms	0.18948	0.27409
Over 106 therms	0.27409	0.27409

	G-2 Lifeline	G-2 Non-Lifeline
Mo. Charge	$3.644	$3.644
First 32 therms	0.22428	0.29754
Next 72 therms	0.21195	0.29754
Next 37 therms	0.20203	0.29754
Over 141 therms	0.29754	0.29754

	G-15 (Charge per lamp per month)
0 - 1.99 cf/hr	$3.68
2.0 - 2.49 cf/hr	5.07

	G-45	G-46
All usage, per therm	$0.27409	$0.29754

	G-50	G-51
All usage, per therm	$0.27415	$0.29760

APPENDIX B

RATES - Northern California Division

	G-10 Lifeline	G-10 Non-Lifeline
Mo. Charge	$4.244	$4.244
First 28 therms	0.35036	0.46968
Next 64 therms	0.27798	0.46968
Next 74 therms	0.27430	0.46968
Over 166 therms	0.46968	0.46968

	G-16 (Charge per lamp per month)
1.99 cf/hr or less	$5.00

	G-60
All usage, per therm	$0.46968

	G-91 (Applicable to both No. and So. Calif. Divisions)
Regular hours	$10.00
After hours	18.00

APPENDIX C

Rates as of December 1, 1976

	G-1 General Lifeline	G-1 General Non-Lifeline
First 2 therms or less	$3.798	$3.811
Next 30 therms per therm	.20911	.21565
Next 43 therms per therm	.19826	.20480
Next 29 therms per therm	.21420	.23116
Next 2 therms per therm	.20542	.23116
Next 412 therms per therm		.23116
Next 518 therms per therm		.22682
Next 2,073 therms per therm		.21997
Next 7,256 therms per therm		.21199
Over 10,365 therms per therm		.20063

	G-1 Heat Only Lifeline	G-1 Heat Only Non-Lifeline
First 2 therms or less		
October - May, Inclusive	$4.868	$4.881
June - September, Inclusive	1.218	1.231
Next 30 therms per therm	.23261	.23915
Next 43 therms per therm	.21047	.21701
Next 5 therms per therm	.22641	.23765
Next 438 therms per therm		.23765
Next 518 therms per therm		.22887
Next 2,073 therms per therm		.22317
Next 7,256 therms per therm		.21826
Over 10,365 therms per therm		.20685

	G-2 General Lifeline	G-2 General Non-Lifeline
First 2 therms or less	$4.078	$4.091
Next 30 therms per therm	.22428	.23082
Next 43 therms per therm	.21195	.21849
Next 29 therms per therm	.22789	.24371
Next 37 therms per therm	.21797	.24371
Next 377 therms per therm		.24371
Next 518 therms per therm		.23880
Next 2,073 therms per therm		.22204
Over 3,109 therms per therm		.22203

APPENDIX C

Rates as of December 1, 1976

	G-2 Heat Only Lifeline	G-2 Heat Only Non-Lifeline
First 2 therms or less		
October - May, Inclusive	$5.258	$5.271
June - September, Inclusive	1.278	1.291
Next 30 therms per therm	.25087	.25741
Next 43 therms per therm	.22576	.23230
Next 29 therms per therm	.24170	.25102
Next 11 therms per therm	.22528	.25102
Next 403 therms per therm		.25102
Next 518 therms per therm		.24120
Next 2,073 therms per therm		.23469
Over 3,109 therms per therm		.22910

	G-10 Lifeline	G-10 Non-Lifeline
First 2 therms or less	$4.95	$5.07
Next 26 therms per therm	.35115	.41027
Next 47 therms per therm	.27877	.33789
Next 17 therms per therm	.28662	.36447
Next 74 therms per therm	.28294	.36079
Next 200 therms per therm		.36079
Next 548 therms per therm		.35466
Next 1,828 therms per therm		.34975
Over 2,742 therms per therm		.34507

	G-12 Lifeline	G-12 Non-Lifeline
First 2 therms or less	$5.175	$5.292
Next 26 therms per therm	.43749	.49661
Next 47 therms per therm	.34014	.39926
Next 17 therms per therm	.34799	.42584
Next 74 therms per therm	.34304	.42089
Next 200 therms per therm		.42089
Next 548 therms per therm		.41264
Next 1,828 therms per therm		.40604
Over 2,742 therms per therm		.40199

APPENDIX C

Rates as of December 1, 1976

Hourly Lamp Rating in Cu.ft.	G-15	G-16	G-18
	(Charge Per Lamp Per Month)		
1.99 cu. ft./hr. or less	$2.47	$4.13	$4.81
2.00 - 2.49 cu. ft./hr.	4.07	6.07	6.93
2.50 - 2.99 cu. ft./hr.	4.77	7.09	8.02
3.00 - 3.99 cu. ft./hr.	5.85	8.77	9.86
4.00 - 4.99 cu. ft./hr.	7.09	10.65	11.85
5.00 - 7.49 cu. ft./hr.	9.70	14.41	16.00

	G-45	G-46
First 1,307 therms per therm	$ .21516	$ .22574
Next 3,110 therms per therm	.20619	.21599
Over 4,147 therms per therm	.20073	.20985

	G-50	G-51
First 10,930 therms per therm . . .	$ .19836	$ .20598
Next 98,370 therms per therm . . .	.19147	.19887
Next 109,300 therms per therm . . .	.18942	.19648
Next 327,900 therms per therm . . .	.18623	.19283
Over 546,500 therms per therm . . .	.18463	.19101

	G-60	G-62
First 525 therms per therm . . .	$ .38067	$ .37139
Next 525 therms per therm . . .	.34444	.33674
Next 1,050 therms per therm . . .	.32718	.32024
Next 8,400 therms per therm . . .	.30821	.30209
Over 10,500 therms per therm . . .	.29354	.28807

	G-91
Regular hours	$6.00
After hours	11.00