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ORIGINAL

Decision No. 83675

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY for authority, among other things, (a) to increase its rates and charges for electric service and (b) to modify certain of its tariff schedules.	Application No. 53945 (Filed April 10, 1973; amended March 5, 1974)
In the Matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY for authority, among other things, (a) to increase its rates and charges for gas service; (b) to include in its tariffs a Purchased Gas Adjustment Clause or an expanded Advice Letter procedure for reflecting in its rates effects of changes in purchased gas costs; and (c) to modify certain of its tariff schedules.	Application No. 53946 (Filed April 10, 1973; amended March 5, 1974)
In the Matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY for authority, among other things, to increase its rates and charges for steam service.	Application No. 53970 (Filed April 17, 1973; amended March 5, 1974)

(Appearances listed in Appendix A)

INTERIM OPINION

PHASE I

At a prehearing conference held August 15, 1973 the above three applications were consolidated for hearing. Hearings were held from November 7, 1973 through April 4, 1974 before Commissioner Moran and Examiner Mattson. The matter of the requested rate relief as set forth in the original applications was taken under submission on April 4, 1974, subject to the filing of briefs.

Prior to the commencement of scheduled hearings, applicant filed a petition for interim rate relief requesting immediate authority for gas and electric rate increases. The hearings on the petition for interim rate relief were held November 7, 8, and 9, 1973. Decision No. 82279 dated December 18, 1973 in these proceedings granted electric and gas rate increases as requested in the petition.

On March 5, 1974 applicant filed amendments to the applications in these proceedings. The amended applications requested rate increases in addition to those originally requested, based upon allegations that conservation (decreased sales) and increases in the cost of capital required further rate relief.

The rate relief originally requested in these three proceedings is under submission as Phase I. The amended applications, requesting further rate relief, have been heard as Phase II of these proceedings. This decision deals with Phase I rate relief matters solely. Phase II will be considered by subsequent decision.

Rate Relief Requested

By original Application No. 53945, SDG&E requested authority to increase electric rates and charges by $17,858,100 on 1974 estimated sales, a gross revenue increase of 9.35 percent. The interim rate relief authorized rate increases of $5,668,700 based on 1973 sales. By amendment to this application on March 5, 1974, SDG&E requested further rate increases of $15,408,300, an increase of 8.61 percent on gross revenues.

By Application No. 53946, SDG&E requested authority to increase gas rates and charges by $7,852,300 on estimated 1974 sales for an over-all revenue increase of 10.44 percent. The interim rate relief granted rate increases of $972,100 on 1973 gas sales. By amendment to the original application on March 5, 1974, applicant requested further rate relief in the amount of $5,135,300, an increase of 6.56 percent on gross revenues.

By Application No. 53970 applicant requested a revenue increase of $56,000 on estimated 1974 steam sales. No interim rate relief was requested in rates and charges for steam service. By amended application, SDG&E requested a further increase in steam rates of $31,000, a 7.41 percent revenue increase.

The rate increases under consideration in these Phase I proceedings are the rate increases originally requested, less the interim rate relief granted by Decision No. 82279. SDG&E requests authorization for the full rate increases originally requested. Based upon 1974 sales in these Phase I proceedings, SDG&E's requested rates would increase its annual gross revenues by the amount of $10,469,700 for its electric department, $5,412,900 for its gas department, and $9,300 for its steam department.

Prior SDG&E Rate Proceedings

The last general rate proceeding reviewing over-all SDG&E operations arose from Applications Nos. 52800, 52801, and 52802, filed August 10, 1971. Rate relief was granted by Decision No. 80432 dated August 29, 1972. Subsequently, this Commission authorized SDG&E to file a fuel clause adjustment applicable to billings for its electric and steam rates by Decision No. 81517 dated June 26, 1973.

General Description of Applicant

Applicant is a privately owned California corporation supplying electrical and gas service in San Diego County in the State of California. Its corporate and executive offices are located at 101 Ash Street, San Diego, California. Applicant operates under local management and supplies electrical, gas, and steam service in a certificated area which includes a population of approximately 1,500,000 in the electrical service area and a population of in excess of 1,000,000 in the gas service area.

Applicant's common stock and preferred stock are publicly traded and held by thousands of individual investors. Applicant secures capital by issuance of common stock, preferred stock, and debt. Its bonds are presently rated "A" and "Aa" (split rated) by the larger financial rating institutions. The stock and debt issues are traded in the financial markets.

A detailed description of the history and operations and affiliated companies will not be set forth in this decision. By Decision No. 80432 dated August 29, 1972, the affiliated relationships, history, and general information regarding applicant's operations are set forth in detail. That information is still generally applicable to this utility and no significant changes in those operations have occurred.

GENERAL DISCUSSION

Issues to be Determined

The rate increase requests are based on the revenue requirements of SDG&E for the calendar year 1974. The applicant and the Commission staff both presented full showings which set forth their respective views on the revenue requirements of SDG&E. They disagreed on a number of issues. The City of San Diego (City) and the Secretary of Defense of the United States also presented evidence and participated in the hearings. The Secretary of Defense appeared on behalf of the federal agencies. The City and the federal agencies have, in part, relied upon the staff showing. They have also presented separate positions on issues where they disagree with the staff and the utility.

Under established regulatory principles, we must answer three basic questions: (1) What will SDG&E earn in 1974 when the operations of the utility are adjusted to reflect average climatic conditions and reasonable levels of revenues, expenses, and rate base; (2) What is the reasonable rate of return which should be applied to the rate base; and (3) How should utility rates and charges be allocated to various classes of customers in order to meet the revenue requirement at the reasonable rate of return. In this case, as in the usual major rate case proceeding, we are presented with the testimony of experts whose estimates and opinions lead to different answers to the basic questions.

In this proceeding, late-filed Exhibit 69 sets forth a comparison of the summaries of earnings of the utility and staff experts on a common basis. A common basis was necessary because of changes in electric and steam rates resulting from the use of the fuel adjustment clauses in SDG&E's electric and steam department tariffs, changing fuel prices and mix, changes in gas department rates, and the frequent changes in the cost of gas. By use of similar rate levels, fuel prices, and mix in Exhibit 69 we are able to isolate and examine the estimates in dispute between the staff and applicant. By resolving the differences between the utility, the staff, City, and the federal agencies, we reach adopted results of operations for the test year.

The conclusions we reach regarding 1974 results of operations, rate base, rate of return, and rate spread are discussed in detail below. In addition, applicant has requested authorization to file a purchased gas adjustment clause (PGA). The staff has recommended that a PGA be authorized, subject to certain provisions. For the reasons set forth in detail in this decision, a PGA clause will be authorized.

As noted above, the rates and charges of SDG&E now in effect include fuel adjustment billing factors. In our authorized rates, we shall include all such amounts in effect to and including October 5, 1974. The rates established by our order will then allow any future fuel clause changes to begin with the base rates, fuel costs, and mix established in this decision.

Rate of Return

This Commission has on numerous occasions discussed the principles applicable to the determination of a fair rate of return. (See San Diego Gas & Electric Company Decision No. 80432 dated August 29, 1972 in Application No. 52800 at pages 13-19; Southern California Gas Company Decision No. 83160 dated July 16, 1974 in Application No. 53797 at pages 36-50; and Pacific Telephone and Telegraph Company Decision No. 83162 dated July 23, 1974 in Application No. 53587 at pages 4-20.) The allowed rate of return is the earning allowance, expressed as a percentage, applied to the test year rate base to determine the amount that the utility will be authorized to earn at authorized rates. It is apparent that small changes in the rate of return allowance will involve very large amounts of money. In short, the determination of a reasonable rate of return is an issue of major importance.

The authorized rate of return is, of course, the result of an exercise of judgment. It is, however, subject to considerable objective analysis. When a rate of return is computed from fixed capital costs and allowances, based upon their relative weight in the capital structure of the utility, the common equity allowance is usually isolated as the major area of dispute. The cost of capital we find applicable to SDG&E is set forth in the following discussion.

Cost of Capital

The cost of capital analysis assumes that a reasonable rate of return must be sufficient to meet all capital costs of the utility. Capital costs of debt and preferred stock may be determined from the evidence. When these costs are multiplied by their respective ratios in the capital structure of the utility, the result is the weighted cost of each in the return allowance. When these weighted costs of capital are combined with the weighted return allowance judged proper for the common equity, the result is the cost of capital to the utility.

The last authorized rate of return for SDG&E was 8 percent. A cost of capital computation based on the 1972 capital costs and ratios used in Decision No. 80432 would be as follows:

Component	Capital Ratio	Allowance or Cost	Weighted Cost
Long-Term Debt	55.47	5.97	3.31
Preferred Stock	13.10	7.07	0.93
Common Equity	31.43	11.96	3.76
Total	100.00%		8.00%

The utility and the staff agree that the Commission should recognize the capital ratios and related costs at year-end 1974 in determining the rate of return allowance in the proceeding. The return authorized should afford applicant an opportunity to achieve reasonable earnings in the near future. Since rates authorized by this decision are based upon the test year 1974, we will adopt year-end ratios and costs.

Rate of Return Request - SDG&E

Applicant's vice president-finance, Ralph L. Meyer, initially testified that his studies established that a rate of return of 8.62 percent was the bare minimum required by the applicant. Witness Meyer urged the return allowance should range from 8.62 to 9.12 percent. This initial evidence was revised by witness Meyer to reflect capital changes in 1974 and the initial minimum request was increased to 8.77 percent. The minimum common equity allowance requested was 12.50 percent in both cases.

Witness Meyer's cost of capital of 8.77 percent was based upon the following capital ratios and costs (Exhibit 60, page 1):

Component	Capitalization Ratios	Rate (%)	Weighted Cost
Long-Term Debt	49.9	6.68	3.34
Preferred Stock	16.0	7.33	1.17
Common Equity	34.1	12.50	4.26
Total	100.0%		8.77%

Rate of Return Recommendation - Staff

Mr. Russell Leonard, the staff financial examiner, recommended a rate of return allowance ranging from 8.40 to 8.55 percent. The 8.55 percent rate of return reflected an 11.97 percent allowance for common equity return, based upon the following ratios and costs (Exhibit 27, Table No. 27):

Component	Capital Ratios	Costs and Allowances	Weighted Costs
Long-Term Debt	49.45	6.58	3.25
Preferred Stock	16.04	7.31	1.17
Common Equity	34.51	11.97	4.13
Total	100.00%		8.55%

It should be noted that witness Leonard recognized that actual costs incurred after the preparation of his exhibit should be recognized. He revised his cost of debt estimate to be 6.64 percent to reflect debt (Series "M") issued after preparation of Exhibit 27.

Capital Ratios and Related Costs - Adopted

The staff and utility both anticipated debt and common stock issues in late 1974. The capital ratios and costs for year-end 1974 incorporated these issues (at estimated amounts and costs) into the outstanding capital. We have adopted capital ratios and costs based upon the evidence of record. We adopt the following ratios, costs and allowances:

Component	Capital Ratios	Allocance or Cost	Weighted Cost
Long-Term Debt	49.82	6.78	3.38
Preferred Stock	16.81	7.38	1.24
Common Equity	33.37	12.38	4.13
Total	100.00%		8.75%

The rate of return we adopt is 8.75 percent. The adopted ratios, costs, and allowances are discussed in detail below.

Long-Term Debt

The staff and the utility witnesses both estimated long-term debt at 1974 year-end.

Witness Meyer for the utility estimated debt in the amount of $415,570,000 at an effective cost of 6.68 percent (Exhibit 60, pages 2, 3). Staff witness Leonard's estimates were $396,000,000 at an effective rate of 6.58 percent, later revised to 6.64 percent. (Exhibit 41, Table No. 5, Tr. 1740).

The utility figures reflected the issuance of $75,000,000 in debt on January 7, 1974 and the concurrent retirement of a $55,000,000 loan. The staff estimate included this transaction, but estimated the cost of the new debt issue (Series "M") at 8.08 percent. The actual coupon rate was 8.375 percent, and the effective cost was 8.42 percent.

The major difference between the staff and utility debt estimates result from an anticipated issue of debt (Series "N") in late 1974. The utility estimated this new debt in the amount of $65,000,000 at an 8 percent coupon rate and an 8.05 percent effective cost. The staff estimated new debt in the amount of $45,000,000 at an estimated cost of 8.11 percent.

Our capital ratios assume a Series "N" debt issue of $45,000,000 at a cost of 9½ percent in late 1974. The estimate of witness Leonard of the staff appears to reasonably reflect the amount of debt applicant may issue. The cost of the issue is estimated as the cost of debt to SDG&E in the 1974 financial market. As witness Leonard testified, these are turbulent times in the financial community and for the last few years the financial market has been in chaos.

The estimated amount of long-term debt of the applicant (Exhibit 60, page 3) should be reduced to reflect the staff's estimate of $45,000,000 for the 1974 debt issue. The cost of the issue is estimated at 9½ percent, and the composite effective cost of debt is 6.78 percent.

Preferred and Preference Stock

The preferred stock of applicant is in the amount of $133,500,000 with a composite cost of 7.38 percent. These figures reflect the actual 1974 stock issued in the amount of $25,000,000 at the cost of 8½ percent. The staff had estimated the amount of the 1974 issue as $20,000,000. Both applicant and the staff underestimated the actual cost of the 1974 issue. Our adopted figure reflects the actual year-end cost.

Common Equity - Amount

The 1973 year-end total common equity was $230,236,000. In 1974 this portion of the capital structure is assumed to increase by a planned issue of common stock and additional retained earnings. We estimate that year-end common equity will be $265,000,000. The applicant's estimated equity figure for 1974 year-end was $284,667,000. However, applicant's estimate was based upon the assumption that the issuance of 2,000,000 shares of common stock in late 1974 would increase year-end equity by $40,000,000. Our estimate is based upon 1974 financial market conditions, including a realistic view of retained earnings. (See Exhibit 41, Table VII, Tr. 1770.)

Common Equity - Allowance

Both witness Meyer for the utility and witness Leonard for the staff introduced extensive studies and testimony in support of their respective recommendations. Witness Meyer testified that 12.5 percent was a minimum earnings figure for the common equity investment. Witness Leonard recommended an allowance for common equity ranging from 11.53 to 11.97 percent. The respective rate of return recommendations were 8.77 percent (witness Meyer) and 8.4 to 8.55 percent (witness Leonard).

We have already set forth our conclusions on the year-end 1974 capital ratios and costs. The 1974 costs of capital have a substantial impact on the rate of return adopted. As witness Leonard observed, continual increases in the cost of debt and preferred stock have generally caused rate of return recommendations to move upward in recent years. In 1972, we found that an 8 percent rate of return would result in an 11.96 percent allowance to common equity. The same 8 percent return, at 1974 imbedded costs, would allow a 10.13 percent return for common equity today.

Viewed another way, an 11.96 percent allowance for common equity, at 1974 imbedded costs, requires an 8.61 percent rate of return. In short, any return below 8.61 percent would include the implicit finding that 1974 earnings allowance for common equity should be lower than our 1972 allowance to SDG&E. The evidence will not support such a finding.

The staff and utility both presented detailed exhibits regarding the cost of capital and rate of return. These studies have been reviewed in detail. Our conclusions regarding costs of senior securities in the capital structure are the result of reflecting the anticipated 1974 changes in the capital structure set forth in the exhibits. Although we do not reproduce in detail the data set forth in the studies in this decision, certain of the evidence regarding common equity earnings will be discussed below.

The utility study presented recorded returns on common equity for allegedly comparable utilities. Twenty companies having both gas and electric service whose 1971 total revenues and capitalization were closest to SDG&E were compared with SDG&E. Witness Meyer stated that since costs and earnings were fairly stable prior to 1970, the period of 1967 through 1969 is more indicative of an adequate return on equity than the years 1970 through 1972. The 20-company average exceeds the 12.5 percent requested by SDG&E in all of the years 1967-1969 (the three years averaged 13.11 percent). Witness Meyer did not use the 1970-1972 data, a period of declining earnings (the three year average was 11.97 percent). Witness Meyer did present 1972 earnings on average common equity for 32 so-called growth utilities. The 1972 average return on common equity of the 32 utilities was 13.6 percent, considerably higher than SDG&E's return of 10.6 percent for 1972.

The staff study included comparisons of SDG&E's operating results with averages of 10 combination gas and electric companies, 10 electric utilities and 10 gas utilities for the years 1968 to 1972. The comparison shows that SDG&E earned 12 percent or more on average common equity from 1968 through 1971, and that the SDG&E earnings rate declined to 10.62 percent in 1972. The five-year average was 11.97 percent for SDG&E. The comparison groups averaged 12.92 percent for the combination utilities, 12.86 percent for the electric utilities, and 12.44 percent for the gas utilities.

The comparison of SDG&E's earnings to comparable groups of utilities is, of course, only one test in determining a proper rate of return. The data reviewed hardly provides an objective standard. However, it is evident that SDG&E's earnings on common equity in recent years has been low when compared with the performance of selected groups of utilities. Applicant is a growth company and must obtain additional capital by the issuance and sale of common stock in the near future. It is not realistic to expect SDG&E to be able to secure equity capital on a reasonable basis unless its earnings are comparable to other similar utilities.

Applicant urges we should authorize a substantial increase above our past allowance for common equity return. But no reason exists to assume that its comparable companies are experiencing dramatic increases in common equity earnings. In fact, the opposite would appear to be the case. In our view, applicant must be afforded an opportunity to achieve earnings comparable to investors in similar utilities. Our allowance for equity in the authorized rate of return is intended to protect the fiscal integrity of applicant under current financial conditions. We do not assume that current conditions cannot change or improve. To the extent conditions in the financial markets may improve, our rate of return may prove to be generous in the future.

Certain outstanding debentures of applicant require that applicant's earnings for a past 12-months' period must be twice the amount of annual interest charges at the time new debt is issued. This debenture computation includes the interest on the new debt issue as part of the annual interest charges in the calculation. The necessity of historical earnings at a level which would meet the requirements of the debenture indenture is obvious, and applicant must have the required earnings coverage in order to issue new debt. Although the calculation under the debenture differs from the cost of capital calculations outlined above, both rate of return witnesses testified that their recommended returns would result in earnings substantially in excess of two times the fixed charges. Our authorized return, at expected capital costs, would result in earnings of approximately 2.6 times fixed charges after taxes, based upon a cost of capital analysis.

If we were to establish a rate of return under normal economic conditions, we would anticipate the authorized rate of return would reflect conditions to be experienced for some period of years in the future. Present economic conditions will not support such an expectation. On the contrary, our assumptions are near term and are based upon the 1974 economic conditions which prevail. To the extent these uncertain economic conditions may change, our rate of return determination must necessarily be reviewed in the future. If possible, the current sharp erosion of common equity earnings should be halted. To the extent our rate of return determination reflects current economic conditions for applicant, the earnings which applicant should be able to achieve in the near future should reflect substantial earnings increases for common equity investment.

Results of Operations - General Discussion

For purposes of comparing the staff and utility estimates of 1974 earnings, Exhibit 69 used a common basis for rates, fuel prices, and mix, gas supply and gas rates. The test year comparisons for SDG&E, combined departments for 1974, resulted in the following differences:

Table 1
Summary of Earnings
Combined Departments
(Year 1974 Estimated)

Item	Utility Exh. 53A Adjusted to Staff's Rev. & Fuel Basis	Difference	Staff Exh. 63 Revised For Tioga Gas
	(Dollars in Thousands)		
Operating Revenues			
From Sales to Customers	$254,925.6	-	$254,925.6
Interdepartmental Sales	9,645.5	-	9,645.5
Miscellaneous	1,295.9	-	1,295.9
Total Operating Revenues	$265,867.0	-	$265,867.0
Operating Expenses			
Fuel & Purchased Power	$ 63,697.6	-	$ 63,697.6
Gas Supply	43,122.9	$(1,005.2)	42,117.7
Production	8,508.5	(375.6)	8,132.9
Storage	556.8	-	556.8
Transmission	4,415.5	-	4,415.5
Distribution	15,789.1	(344.6)	15,444.5
Customer Acctg. & Coll.	8,180.3	(176.6)	8,003.7
Marketing	1,696.9	(278.6)	1,418.3
Administrative & General	20,643.3	(325.2)	20,318.1
Subtotal Expenses	$166,610.9	$(2,505.8)	$164,105.1
Depreciation & Amortization	$ 26,767.9	$ 3.0	$ 26,770.9
Ad Valorem Tax	14,342.4	(0.4)	14,342.0
Payroll Tax & Miscellaneous	1,600.7	(50.7)	1,550.0
State Franchise Tax	1,200.9	226.6	1,427.5
Federal Income Tax	2,765.8	(489.6)	2,276.2
Wage & Productivity Adjustment	161.3	(150.4)	10.9
Total Operating Expenses	$213,449.9	$(2,967.3)	$210,482.6
Net Operating Revenues	$ 52,417.1	$ 2,967.3	$ 55,384.4
Depreciated Rate Base	$692,747.2	$(1,587.3)	$691,159.9
Rate of Return	7.57%	0.44%	8.01%

The preceding comparison reflects differences between the utility and staff showings at hearing. It does not reflect the differences which would result from use of estimates and adjustments supported by evidence and argument of the City and the federal agencies. The issues raised by those parties are considered and discussed where they are applicable in our review of the estimates. Moreover, the gas supply expenses assume increases from Southern California Gas Company's (SoCal) Application No. 53797. Increases were authorized in the SoCal proceeding by Decision No. 83160 dated July 16, 1974. SDG&E has offset the effect of those increases pursuant to authority granted by Decision No. 82526. The result is that the gas supply expenses are overstated in the above comparison, and in our adopted results we will include the gas supply expenses and revenues which result from the SoCal increase authorized by Decision No. 83160 and the SDG&E offsetting rate increase.

The differences reflect certain disputes regarding expenses common to all departments. No dispute exists regarding allocations of these common expenses in the staff and utility evidence.

Results of Operations, All Departments

Our conclusions regarding the proper estimates of expenses common to all departments is as follows:

Customer Collection Expenses - Accounts 903.3 and 903.6

Under the title Customer Accounting and Collections, the utility and staff witnesses differ as to the estimates in Account 903.3 (Collections) and Account 903.6 (Data Processing). The staff estimated amounts in those two expense accounts are $54,100 lower than the utility estimate in each account for the electrical department and $34,200 lower in each account for the gas department. (See Exhibit 69, page 1, columns (g) and (h); page 6, columns (b) and (e).)

Staff witness Peeples testified in support of the staff estimated customer account expenses. Witness Peeples testified that he developed estimates by use of five-year least squares trending. Data for the years 1968 to 1972 were adjusted to a constant wage level, trended to 1974, and then adjusted to the 1974 wage rate. Witness Peeples testified that a customer information system (CIS) was developed by the utility in 1968 and is expected to be in full operation in 1974. Development costs of the CIS system were removed from the accounts where they occurred, and after the development of a basic cost for each account for 1974, the amounts expected to be incurred by the company due to CIS were added back into the accounts. Witness Peeples testified that based on historical data it was reasonable to assume that the CIS expenses will be incurred. Account 903.6 (Data Processing) was affected by the CIS cost.

Witness Peeples testified that in accounts where an observed indicated steady downward trend did not appear in the final year 1972, he reviewed data for the 12 months ending June 1973, or the most recent period he could obtain. He determined the figures were again on the downward trend.

The utility figures for these accounts were presented by witness Parsley. Witness Parsley testified that in the accounts involved, except for postage and uncollectibles, he started with 1972 recorded data and added costs for increased wages and increased customers. As to customer information service costs, witness Parsley deducted those costs before he calculated cost per customer, and then added back in the cost of the CIS after developing his 1974 estimates. Witness Parsley testified that the development costs for CIS substantially dropped in the year 1974.

The utility attempted to support its position on the disputed accounts in its rebuttal exhibits, Exhibits 54 and 55, related to electrical and gas departments. The utility rebuttal exhibits attempt to support the utility's higher estimates in those two accounts. The claim made is that the actual cost per customer in the accounts for the five years 1969-1973, recorded, did not show that the cost per customer is decreasing. However, the utility made no effort to determine the actual wage adjusted trended results in order to establish estimated figures for test year 1974. Moreover, the effort to contrast 1973 recorded expenses in those accounts with the staff's estimate for 1974 does not discuss the CIS expenses, which were removed in the trending computation by the staff witness and by the utility witness in developing cost per customer data. The utility witness stated that the cost of the development of CIS dropped substantially in the year 1974, and indicated there might be minor changes in the year 1974.

For test year 1974 the staff estimates for Account 903.3 (Collections) and in Account 903.6 (Data Processing) will be adopted. The use of the staff's trended data rather than a single year's experience should produce a more reliable estimate for the test year 1974.

Wage and Productivity Adjustment

The staff and the utility both reflected a March 1, 1974 wage increase of 6 percent for the entire test year. This was an increase from an estimated 5.5 percent wage increase reflected in the utility's original exhibits. However, the staff applied a 5.8 percent productivity factor to a two-months' period in which the 6 percent wage increase was recognized. The staff witness explained that the productivity factor was based upon the Bureau of Labor Statistics Bulletin 1780, 1973 Edition, Table 82, Gas and Electric Utilities Indexes of Output Per Man-Hour and Output Per Employee. The average annual rate for the years 1960 through 1972 is 5.8 percent output per man-hour of increased productivity. The effect of the application of the 5.8 percent productivity factor was a reduction in the staff's estimated expenses for the test year of $152,800.

The calculation and application of the productivity factor is set forth in staff Exhibit 32, pages 6 and 7, and the adjustment was applied to all departmental reports wherever the term "wage and productivity adjustment" appeared.

The difficulty with the use of the productivity index is that it appears to apply productivity factors twice to the test year estimates. In staff Exhibit 31, in his prepared testimony witness Peeples stated that the staff method of trending expenses for five years clearly shows for most accounts a decrease in unit cost per customer. That is an indication of increased productivity within each account as customers are added. Witness Peeples, testifying as to the appropriate estimates for certain customer accounts, testified that the utility's method did not reflect the trend in increased productivity. It would appear that by acceptance of the staff's estimates for test year 1974, we have properly reflected the current increased productivity which may be available to the utility. The use of estimates from data trended by the staff appears to be adequate recognition of the current productivity increases available to the utility. Under the circumstances, the staff's wage and productivity adjustment will not be adopted.

State Unemployment Insurance Tax Rate

The state unemployment insurance rate (SUI) used by the staff was 1.7 percent. The staff witness explained that the rate is based upon the company's experience and several other factors. It is a rate agreed upon by the utility and the Department of Human Resources of the State of California and fluctuates from year to year. The staff used 1.7 percent, the average of the 1967 to 1973 tax rate for the utility. The staff witness did trend the last five years, but the result was a very high figure.

The utility used 2.2 percent, the 1973 tax rate. The record demonstrates that this tax rate does fluctuate from year to year. However, the record does not afford any basis for an assumption that the 1974 rate will be substantially lower than 1973. The rate has increased from 1971 through 1973. Under these circumstances, we will adopt 2.2 percent.

Marketing - Sales Expenses - Accounts 911, 912, 913, and 916

The utility's vice president-marketing, witness Hamrick, expressed the opinion that the Commission, in Decision No. 80432 dated August 1972, had little evidence before it to judge whether it was right or wrong in making its allowances for sales expense. The expense items in dispute are found in Accounts 911, 912, 913, and 916. The utility labels these accounts "Marketing Expenses" (Exhibit 3, Table 7-A) and the staff title is "Sales Expenses" (Table 7-A, Exhibit 33). With witness Hamrick's admonitions in mind, we have attempted to determine the appropriate allowance for sales expenses by a careful review of the record in these proceedings.

Witness Hamrick testified that the company did not attempt to show comparability of account numbers between San Diego Gas & Electric Company and other California utilities because they were not sure that the companies can be compared with information that is pertinent. The utility had attempted to compare San Diego Gas & Electric Company with several other California utilities on a cost per customer per year on sales expense, but had been unable to show comparability of account numbers. However, witness Hamrick stated that "we still feel we are below the levels of expenditures of the other companies."

Witness Hamrick's prepared testimony regarding the electric department marketing expenses advanced a number of reasons in support of the electric marketing expenses. Witness Hamrick is undoubtedly correct that certain energy conservation utilization activities, costs of communicating with customers in this regard, and salaries and office expense for supervision of such activities would include marketing functions that could be found to benefit customers. However, witness Hamrick used recorded electric marketing expenses for the year 1972 and expected expenses for 1973 and 1974 to support his estimated test year expense. The figures presented by witness Hamrick show that the proposed 1974 test year expense is 31 percent above the recorded electric marketing expenses for 1972. Witness Hamrick stated that the increase is due to a rise in labor costs and that the steady growth of customers is reflected in the added expense. Witness Hamrick testified that promotional efforts have been supplanted with customer advisory and communications functions which have the goal of optimizing appliance usage for most efficient operation and for energy conservation.

The staff witness developed a total sales expense figure per customer to be allocated to the electric and gas departments, based on two major considerations. One was the Commission's last decision regarding this utility. In Decision No. 80432 dated August 29, 1972 the Commission allowed a fixed dollar amount as a reasonable allowance for sales expenses for test year 1972. The other consideration was a study of actual expenditures of this utility in recent years, both on an adjusted wage level equivalent to March 1, 1972 wages and on an unadjusted actual expenditure level. The staff witness then developed an estimate for 1974 on a per customer cost basis, including wage increases incurred in 1973 and 1974. The staff witness stated that in recent years the company has engaged in conservation rather than promotional activities, but stated that there is still room for heavier emphasis on conservation. The staff witness would disallow all expenses incurred for the company's "Lite Lines" document included with each customer's bill. The staff witness stated the recent Commission's decisions place a strong emphasis on discouraging promotional advertising and limiting sales and advertising expenses in general.

We have directed California utilities to inform their customers of the need for conservation. The utility urges that its marketing expenses should be authorized as expenditures required by our Decision No. 82881 dated May 15, 1974 in Case No. 9581. The utility was ordered by Ordering Paragraph 3, page 16, of that decision to provide general information to its customers by appropriate advertising and notices setting forth conservation objectives. The utility urges that the requirements for this type of communication justify increased expenses.

The direct evidence of the Commission staff witness indicates that his allowance, on a cost per customer basis, is an increase in the amount last authorized by this Commission for marketing expenses. (The utility argues that it has redirected its expenditures in this area in order to advertise conservation programs as required by this Commission. The utility's argument fails to justify the large increases in expenditures in these accounts.)

We agree with the utility's witness that across-the-board reductions are not helpful in evaluating appropriate sales expense items. However, there is no indication in the evidence advanced on behalf of the utility that the utility has, by redirection of its advertising efforts and appropriate reductions, made an effort to reduce its total expenditures in its per customer expenditures in this marketing expense area. On the contrary, it would appear that an increase in the utility estimates for 1974 over actual 1972 in excess of 30 percent would have the effect of offsetting the reductions ordered by our last decision. It would appear that redirection of advertising efforts into the conservation field and recognition of the appropriate levels authorized by past Commission decisions should result in substantially lower 1974 estimates.

Under the circumstances, we have adopted the staff witness' estimates for these accounts. The effect of the adoption of the staff figures is to reduce marketing expenses by $181,400 in the electric department and by $97,200 for the gas department.

Administrative and General Expenses

The staff and the utility are in disagreement about the appropriate allowances for certain administrative and general expenses. Specifically, the staff disallowed a portion of institutional advertising in Account 930 and under the miscellaneous and general expenses, the staff disallowed certain contributions, dues, and donations. Staff witness Silbert eliminated $150,000 from the electric department expenses for a research project which had been postponed. The utility accepted this adjustment.

The Commission in its last general review of this utility in Decision No. 80432 dated August 29, 1972 followed the staff's recommendations in adjustment of claimed expenses for dues, donations, and contributions. We also adopted the staff's reduction of institutional and goodwill advertising by 50 percent. Staff witness Silbert testified that he disallowed a $102,000 United Fund contribution which the company had included in Account 930 for the test year. Staff witness Silbert testified on the basis of several years' experience he disallowed $120,000 in dues and donations. He did allow some substantial amounts in contributions, donations, and membership dues that appeared in the account. He disallowed 20 percent of the institutional and good will advertising he found in Subaccount 930.18.

The utility's evidence regarding the disputed estimates for Account 930 was presented by witness Parsley who testified as to the budgeted amounts for 1973 and estimated 1974. The basic position of the utility appeared to be that Account 930 contained the expected expenditures of the utility and, therefore, should be recognized for ratemaking purposes. The utility included $102,000 donated to the United Fund in the contributions it expensed for ratemaking purposes. Witness Parsley testified that Account 930 included the amounts expended for institutional advertising in the amount of $370,380. He further testified that trended amounts would be above the budgeted figures that he used and that the 1972 institutional goodwill advertising totaled $318,805. On cross-examination it appeared that the Account 930 contributions, dues, and donations of the electric department for the year 1972 was $212,220 and that the utility's 1974 electric department estimated increase was in excess of $700,000. Witness Parsley testified that the electric department dues and donations figure for 1972 for the electric department of $212,220 could be contrasted with $1,036,295 for 1974 as expected.

We share the concern of the witness for SDG&E regarding appropriate expense allowances in the disputed accounts. However, the staff exclusion of dues and donations is consistent with the Commission's declared policy of excluding dues, donations, and contributions by a utility from operating expenses for ratemaking purposes. This is a policy which has been not only upheld by the California Supreme Court, but declared to be correct for ratemaking purposes. (See Pacific Tel. & Tel. Co. v Public Utilities Commission (1964) 62 Cal 2d 634 at 668, 669.) A detailed discussion of this area is set forth in our recent decision on Southern California Edison Company's Application No. 53488 filed August 1, 1972, Decision No. 81919 dated September 25, 1973, at page 44.

The disallowance of institutional advertising of the staff will be followed. SDG&E is advised that the necessity of discontinuing load building advertising should reduce costs. Compliance with the Commission's orders in Cases Nos. 9581 and 9642 regarding conservation does not support ever-increasing advertising expenditures. The utility has not demonstrated a long-term program of curtailment in these expense areas, and has not even demonstrated that in recent years it has attempted to reduce the expense per customer incurred in its activities in these areas. (See Public Utilities Code Section 796(a).)

The Commission is prepared to recognize necessarily incurred expenditures in a curtailment advertising program. However, the ever-increasing expenditures of this utility in the disputed accounts leads to the question of whether or not the disallowances are, in fact, too small in these areas. We would expect a more thorough presentation of the past and present levels of expenditures of this utility in any future proceeding.

The staff estimates are accepted in the Administrative and General Expenses in Account 930. The effect as set forth in Exhibit 69 is to disallow $228,500 of expenses for the electric department and $96,000 in the gas department expenses. (See Exhibit 69, pages 2 and 7.)

State Franchise Tax

A resolution of differences in the prior items in dispute relative to operating revenues or operating expenses will, of course, be reflected in the tax calculation. However, the state tax computation is in dispute. The staff included as an expense deduction in calculating state income tax the amount of dues and donations disallowed as an expense for ratemaking purposes. We have adopted the staff disallowances of contributions, dues, and donations. Having disallowed an item as an expense for ratemaking purposes, it would be inconsistent to calculate taxes as if the contribution expense had been incurred and allowed. It is true that the ratepayers lose the benefit of a tax deduction by the disallowance of the contribution, but it is also a fact that they are not charged for the actual expenditure made by the utility.

In adopting the utility's view of the proper treatment of this item, we note that we have departed from the actual taxes paid in order to establish proper revenue requirements on a test year basis to ratepayers. Computations of the state tax liability will exclude expense items disallowed to the utility in the test year. The "nonutility" interest expense is also excluded for the reasons set forth in our discussion on federal income tax, infra.

Federal Income Tax

The allocation of the contributions to below the line items affects the computation of federal income tax. Having disallowed the contributions for ratemking purposes, as expenses, such contributions will not be used to reduce the tax liability of the utility. As noted above, the ratepayers may lose the benefit of a lower tax liability, but they have not been required to pay for the contribution expense incurred by the utility.

A substantial dispute between the utility and the staff regarding the computation of federal income tax occurs at present rates in what is labeled ITC (investment tax credit) determination. ITC is now identified as JDIC (job development investment credit). While the utility and the staff are agreed on the amount of an allocation of interest expense to "nonutility" operations, they are in disagreement as to the proper use of this allocation in the computation of JDIC credit. As explained by the utility witness Higgins, there is an allocation of an interest deduction for income tax purposes above and below the line for utility and nonutility activities of the utility. However, "nonutility" does not include the activities of the subsidiaries of SDG&E. The non-utility interest in the computation is an allocation of interest expense based upon the net investment between the utility plant in service and CWIP (construction work in progress) incomplete, the latter being described as the nonutility portion. The comparison between these two net investment amounts gives a percentage figure on which the interest expense allocation is made.

The problem arises in the JDIC allowance in the computation of the federal income tax. JDIC is limited in any given tax period to 50 percent of the total tax liability. The staff, in computing federal income tax liability and the allowable amount of JDIC, allocated the interest expense below the line prior to computing the JDIC allowance. The effect was to reduce the interest expense deduction attributable to utility operations, which resulted in a greater tax. For SDG&E, the result was a greater JDIC allowance than computed by the utility.

The utility computed the JDIC allowance as limited to one-half of the federal income tax liability based upon a lesser tax liability. The lesser federal income tax liability resulted from the use by the utility of all contribution expense items and all interest expense items which were subsequently allocated below the line. The result was to utilize higher expense deductions in the computation of SDG&E tax liability, and one-half of the resulting tax liability limited the use of the available JDIC. In fact, under the computation of the utility all of the JDIC otherwise available could not be used to reduce federal income tax.

The argument of the utility is that the staff calculation by staff witness Silbert clearly overstated the tax credit available and understated the federal income taxes for the utility operations. However, the utility argument is grounded upon the tax law applicable, which limits JDIC to one-half of the tax liability regardless of the above the line and below the line allocations required in setting rates.

Although the amount in dispute appears large in the comparison for test year purposes at present rates, it should be noted that at the earnings levels authorized in this decision, there is a substantial increase in tax liability. The effect of this increased tax liability is to increase available JDIC under the method used by the utility in the tax calculations.

It does appear that the staff witness Silbert has advanced a calculation which is consistent with our ratemaking principles in that the computation of the utility involves an assumption that tax liability will be determined for the ratepayers based upon expense items which are not included in utility operations for ratemaking purposes.

Our determination is that the staff method is correct. The staff's computation of the JDIC would be applicable to the state tax paid deduction used in the computation of the federal income tax. The allocation of interest to the nonutility operations was made by the staff prior to calculating the utility state tax deduction. This calculation results in an increase of the state income tax and creates a larger deduction for federal tax purposes. The result is to reduce the federal income tax liability for ratemaking purposes.

Results of Operations - Gas Department

The summary of earnings for the combined departments at Table 1 sets forth a comparison of utility and staff estimates. The combined departments summary is, of course, based on summaries for the separate departments as set forth in Exhibit 69. In addition to the differences in estimates which we have already discussed, certain differences in the estimates are applicable to separate departments. The summary of total differences between the staff and the utility for the gas department is as follows:

Table 2

Summary of Earnings

Gas Department

(Year 1974 Estimated*)

Item	Utility Exh. 55A Adjusted to Staff's Revenue Basis	Difference	Staff Exh. 65 Revised For Tioga Gas
	(Dollars in Thousands)		
Operating Revenues			
From Sales to Customers	$ 66,458.5	-	$ 66,458.5
Interdepartmental Sales	9,645.5	-	9,645.5
Miscellaneous	284.2	-	284.2
Total Operating Revenues	$ 76,388.2**	-	$ 76,388.2**
Operating Expenses			
Gas Supply	$ 43,122.9	$(1,005.2)	$ 42,117.7
Storage	556.8	-	556.8
Transmission	767.5	-	767.5
Distribution	6,089.1	-	6,089.1
Customer Acctg. & Coll.	3,147.5	(68.4)	3,079.1
Marketing	593.0	(97.2)	495.8
Administrative & General	6,759.6	(96.0)	6,663.6
Subtotal Expenses	$ 61,036.4	$(1,266.8)	$ 59,769.6
Depreciation & Amortization	$ 5,358.9	-	$ 5,358.9
Ad Valorem Tax	2,788.1	-	2,788.1
Payroll Tax & Miscellaneous	560.3	$ (18.0)	542.3
State Franchise Tax	(85.4)	116.7	31.3
Federal Income Tax	(766.2)	734.2	(32.0)
Wage & Productivity Adjustment	52.5	(48.8)	3.7
Total Operating Expenses	$ 68,944.6	$ (482.7)	$ 68,461.9
Net Operating Revenues	$ 7,443.6	$ 482.7	$ 7,926.3
Depreciated Rate Base	$121,871.5	-	$121,871.5
Rate of Return	6.11%	0.39%	6.50%

* Gas rates at 2/16/73 levels plus interim increase; and gas supply including full-year effect of SoCal increase proposed in Application No. 53797.

** See Exhibit 70, sheet 2, columns (d) plus (h), line 11.

Both the staff and utility assumed an increase in gas supply costs from SoCal's pending rate proceeding in Application No. 53797. However, SDG&E had been authorized to increase its rates to offset this gas supply expense increase by Decision No. 82526. As we stated earlier, our adopted results will reflect the increased gas supply costs for the increases authorized SoCal by Decision No. 83160 dated July 16, 1974 in Application No. 53797 and the offsetting revenues.

The differences between the utility and the staff common to all departments have already been discussed. Our determinations of the differences for the gas department are discussed below. The estimates we adopt are set forth in each item discussed.

In the gas department results of operations, certain differences result from the effect of Tioga Wells LNG gas that SDG&E will receive commencing in 1974. By Decision No. 82716 dated April 9, 1974 in these proceedings, we determined that this supply of gas would be recognized in the 1974 test year on an "as expected" basis. However, the staff and the utility differ on the cost to be recognized in the test year. The gas deliveries anticipated for the 1974 test year are set forth in Exhibit 73 in these proceedings. Exhibit 73 is based upon our Decision No. 82716 as modified by the Southern California Gas Company gas balance work sheet dated April 11, 1974 prepared in accordance with the presiding examiner's ruling in Phase II proceedings in Application No. 53797 of the Southern California Gas Company. Exhibit 73 reflects the gas deliveries utilized in the Southern California Gas Company Application No. 53797, as adopted by Decision No. 83160.

The differences on issues common to all departments have been resolved in our discussion of results of operations for the combined departments. Those relate to the staff disallowance of marketing and advertising expenses, staff's estimates of allowable dues and donations, the use of different California unemployment insurance (SUI) tax rates, state franchise and federal tax differences due to the taxable income differences resulting from the expense allowances, tax differences due to allocation of contribution deductions, state and federal tax differences due to allocation of interest expense below the line, computation of the job development investment credit (JDIC), and the staff's use of a productivity allowance in the wage adjustment.

Tioga Wells Gas & Peaking Demand Charges

Decision No. 82716 dated April 9, 1974 established SDG&E's 1974 estimated gas requirements and included a supply of California LNG from the Tioga Wells contract. The requirements and deliveries were changed as a result of the adopted gas balances for Southern California Gas Company for test year 1974 by Decision No. 83160. Exhibit 73 in these proceedings reflects the adopted requirements in deliveries to SDG&E.

We have adopted the cost of Tioga Wells gas as estimated at \$1.894 M^2 Btu. The staff urges the cost of this gas be recognized only to the extent that revenue is generated by the new supply of gas. For the test year, the staff would allow expenses for the California LNG only to the extent revenues are generated by interdepartmental sales of gas at the G-54 rate. The staff position appears to be that consideration of the California LNG gas costs should be deferred until such time as they may be considered in a future PGA filing (the staff recommends the adoption of a purchased gas adjustment clause). The staff supports its position by noting that a delay has occurred in the LNG deliveries.

We have already determined that it is reasonable to recognize the LNG gas supply for the test year 1974. The gas supply is on a long-term contract, and it is reasonable to assume deliveries will commence before the rates established herein are in effect. Under the staff treatment the recognition of the cost of the California LNG would be allowed only to the extent the G-54 rates generated revenues for the gas department. To the extent G-54 revenues would not meet the LNG gas costs of the new supply, the staff would disallow such costs at this time.

The cost of the California LNG is substantially in excess of the present cost of gas purchased from Southern California Gas Company. However, there is no evidence that SDG&E management could obtain new supplies of gas at substantially lower costs elsewhere. In fact, given the critical gas supply situation in the test year, there is no evidence that any other new supply of gas was available to SDG&E management. The Commission, of course, will not necessarily endorse any management action. But the test of reasonableness of the costs assumed by SDG&E to secure new gas supply must be examined in light of the alternate energy sources available to this utility, not historical costs of gas from the existing suppliers. The utility acted to secure by long-term contract a new supply of California source LNG. Based upon the alternatives available to the utility, we cannot say that the management action was unreasonable.

We have compared the cost of the California LNG supply with the cost of alternate fuels available to the electric utilities generally in 1974. The staff position appears grounded upon the fact that the new gas supply will be used by the electric department of SDG&E in the test year. The new LNG gas supply results in substantial gas supply expense increases which will be borne by gas department customers to the extent the increased costs attributable to California LNG exceeds the G-54 revenues generated for the gas department. This fact must be considered in establishing rates. But this problem will exist whenever added increments of new gas supply exceed the cost of existing supply. Given the historical cost of pipeline gas to the utilities in the State of California, it appears highly unlikely that new supplies of gas will be secured at a price not in excess of existing costs.

Under the circumstances we are recognizing the Tioga Wells gas supply in accordance with the deliveries set forth in Exhibit 73. We are recognizing the estimated contract price of the Tioga Wells gas pursuant to the evidence of record.

Peaking and demand charges from Southern California Gas Company are adopted in accordance with Decision No. 83160, our recent general rate decision for Southern California Gas Company. Such peaking and demand charges are applied to the test year 1974 as they are expected to be incurred. Future changes, if any, may be reflected in PGA rate changes.

Gas Department - Adopted Results

Based upon the preceding determinations, Table 3 sets forth the test year adopted results of operations for the gas department. We have included the impact of the actual gas costs and related changes from our SoCal decision, as well as the offsetting revenue.

The dispute between the staff and the utility regarding the computation of available JDIC does not affect the final revenue requirements, for all available JDIC is utilized at the authorized rate of return. For this reason, we do not intend by this decision to necessarily resolve all issues which may arise regarding the appropriate treatment of JDIC.

The gas department revenues will be increased by $1,994,100 annually to reflect the revenue requirement at an 8.75 percent rate of return.

Results of Operations - Electric Department

We have discussed items in dispute between the utility and the staff that are common to all departments. Certain differences in results of operations exist between the utility and the staff for the electric department only. Those disputes relate to certain production expenses, Accounts 502, 510, 551-554; distribution expenses in Accounts 587 and 593, and a dispute as to a rate base item involving transmission towers in the Materials and Supplies (M&S) account.

TABLE 3

San Diego Gas & Electric Company
Gas Department

COMPARISON OF UTILITY AND ADOPTED SUMMARIES OF EARNINGS - 1974

Item	Utility's Exh.55A Adjusted to Staff's Revenue Basis	Impact of So.Cal. D-83160 and SDG&E Adopted Offsets	Total Effect of Adopted Estimates Plus Col. (b) Effect	Adopted Results Without Revenue Increase	Adopted Results At 8.75% Rate Of Return
	(a)	(b)	(c)	(d)	(e)
	(Dollars in Thousands)				
Operating Revenues					
From Sales to Customer	$ 66,458.5	$ 1,351.0	$ 1,351.0	$ 67,809.5	$ 69,339.6
Interdepartmental Sales	9,645.5	459.4	459.4	10,104.9	10,558.3
Miscellaneous	284.2	-	-	284.2	294.8
Total Operating Revenues	76,388.2	1,810.4	1,810.4	78,198.6	80,192.7
Operating Expenses					
Gas Supply	43,122.9	(1,592.1)	(1,592.1)	41,530.8	41,530.8
Storage	556.8	.4	.4	557.2	557.2
Transmission	767.5	2.3	2.3	769.8	769.8
Distribution	6,089.1	-	-	6,089.1	6,089.1
Customer Acctng. & Coll.	3,147.5	3.0	(65.4)	3,082.1	3,084.7
Marketing	593.0	-	(97.2)	495.8	495.8
Adm. & Gen.	6,759.6	44.5	(51.5)	6,708.1	6,746.0
Subtotal Expenses	61,036.4	(1,541.9)	(1,803.5)	59,232.9	59,273.4
Depreciation & Amort.	5,358.9	-	-	5,358.9	5,358.9
Ad Valorem Tax	2,788.1	-	-	2,788.1	2,788.1
Payroll Tax & Misc.	560.3	-	-	560.3	560.3
State Franchise Tax	(85.4)	301.7	325.2	239.8	415.6
Federal Income Tax	(766.2)	1,464.3	993.0	226.8	1,080.1
Wage & Productivity Adj.	52.5	-	-	52.5	52.5
Total Operating Expense	68,944.6	224.1	(485.3)	68,459.3	69,528.9
Net Operating Revenue	7,443.6	1,586.3	2,295.7	9,739.3	10,663.8
Depreciated Rate Base	121,871.5	-	-	121,871.5	121,871.5
Rate of Return	6.11%	1.30%	1.88%	7.99%	8.75%

(Red Figure)

The differences are reflected in the electric department summary of earnings comparison as set forth in Exhibit 69, as follows:

Table 4

Summary of Earnings

Electric Department

(Year 1974 Estimated*)

Item	Utility Exh. 54A Adjusted to Staff's: Rev. & Fuel Basis	Difference	Staff Exh. 64 Column (c)
	(Dollars in Thousands)		
Operating Revenues			
From Sales to Customers	$187,990.3	-	$187,990.3
Miscellaneous	1,011.7	-	1,011.7
Total Operating Revenues	$189,002.0**	-	$189,002.0**
Operating Expenses			
Fuel & Purchased Power	$ 63,446.2	-	$ 63,446.2
Production	8,450.9	$ (375.6)	8,075.3
Transmission	3,648.0	-	3,648.0
Distribution	9,658.2	(344.6)	9,313.6
Customer Acctg. & Coll.	5,031.2	(108.2)	4,923.0
Marketing	1,103.9	(181.4)	922.5
Administrative & General	13,822.5	(228.5)	13,594.0
Subtotal Expenses	$105,160.9	$(1,238.3)	$103,922.6
Depreciation & Amortization	$ 21,382.5	$ 3.1	$ 21,385.6
Ad Valorem Tax	11,535.7	-	11,535.7
Payroll Tax & Miscellaneous	1,032.4	(32.4)	1,000.0
State Franchise Tax	1,288.3	109.9	1,398.2
Federal Income Tax	3,543.4	(1,224.2)	2,319.2
Wage & Productivity Adjustment	108.8	(101.6)	7.2
Total Operating Expenses	$144,052.0	$(2,483.5)	$141,568.5
Net Operating Revenues	$ 44,950.0	$ 2,483.5	$ 47,433.5
Depreciated Rate Base	$570,544.2	$(1,581.5)	$568,962.7
Rate of Return	7.88%	0.46%	8.34%

* Electric rates, fuel price and mix at Decision No. 80432 levels plus interim increase.

** See Exhibit 70, sheet 1 sum of columns (b) and (c), line 11.

Production Expenses

a. Account 502 - Operation, Steam Expenses

In developing estimated production expense for Account 502, both the utility and the staff derived their estimates from trended data. Witness Watkins testified on behalf of the utility. He stated that for Account 502 he trended data from 1966, corrected to a March 1, 1972 wage base. Staff witness Endres stated that he arrived at his estimated expenses for Account 502 by trending five years of recorded data, adjusted to the March 1972 wage level. Witness Endres trended the five years' data by use of a least squares method and adjusted his result to the 1974 wage level.

The utility urges that we accept the trended estimates presented by its witness, based upon the actual expense incurred in 1973, adjusted to a common wage level. The staff witness recognized that the 1973 recorded data did fall above his trend line, but noted that the recorded data appearing on the utility's trend line would fall above and below the trend line.

We will adopt the staff trended estimate for Account 502. It is clear that the staff witness was of the opinion that the actual 1973 results were not inconsistent with his estimate, as he observed that actual results would fall above and below his trend line. The result is that production expenses are reduced from the utility's estimate by $115,900.

b. Account 510 - Supervision and Engineering

In estimating expenses for Account 510, the utility witness Watkins stated that he did not use his basic procedure of taking historical data back to 1966. He indicated that there had been changes in alignment of groups within the company which made the historical data of the account untrendable. Staff witness Endres developed his estimated expense by trending the recorded adjusted expenses of the account for 1968 through 1972. He carried the trend through 1973 and 1974 and adjusted for 1974 wages. In addition, he reflected the addition of Encina Unit No. 4 by an additional adjustment of $32,000. Staff witness Endres testified that the account did fluctuate substantially, but that an examination of month-ending expense figures for the account did not indicate that the year-ending points being trended changed the result, in that the use of 60 month-ending points would not appear to dampen the fluctuations that appeared in the trend line. Witness Endres testified that the five year-end points appeared representative of the 60 month-ending points for the account. Moreover, witness Endres was of the view that supervision engineering represented by this account is within the control of the utility and that a trend of the last five years appeared to be a reasonable approach.

We agree with the staff witness. For Account 510 the staff estimates are adopted for test year purposes. The staff estimates are $32,000 below the utility estimated expense.

c. Gas Turbine Maintenance, Accounts - Accounts 551-554

Accounts 551 to 554 involve estimates of expense for gas turbine maintenance. Witness Watkins on behalf of the utility testified that he trended 25 months to 12 months' periods of historical expenses per unit and trended the expense per unit into the future. The data used by witness Watkins ended August 1972. It appeared that when there are major gas turbine overhauls, as in 1971, the accounts are substantially larger than in years when there are no major overhauls in gas turbines (as in 1972). In 1973 there were several major failures of gas turbine reduction gears requiring extensive maintenance.

Staff witness Endres testified that his estimates for Accounts 551 through 554 was based upon recorded 1972 expenses per unit. Expenses per unit were adjusted to March 1972 wage levels as the base for the 1974 estimate. Adjustments were made to this base for labor and materials to reflect 1974 levels and the expense per unit was multiplied by the anticipated average number of units in 1974. The estimate was increased by $50,287 for the amortization over three years of unusually large expenses experienced in 1971. The staff witness stated that the recorded gas turbine per unit maintenance expenses fluctuate widely from year to year.

It is clear that the expenses in these accounts fluctuate widely from year to year on a per unit basis. At March 1972 wage levels the recorded expenses per unit were $21,100 for 1971 and $30,400 for 1973. In these accounts neither the staff nor the utility attempted to develop any long-term trend. The staff amortization of 1971 expenses deemed unusual implies that the use of 1972 data results in an inadequate allowance for this expense. From the evidence available, it does not appear that the unusual expense recognized by the staff in 1971 is peculiar to that year. Per unit cost in 1973 increased almost 50 percent above the 1971 experience. Under those circumstances we will accept the estimates of the utility, which reflects an effort to trend those expenses. Based upon the available information the utility estimate in Accounts 551 to 554 will be adopted for test year 1974. The result is that the expenses are $227,700 higher than the staff estimates for these accounts.

Electric Distribution Expenses

a. Operation - Customer Installations, Account 587

The customer installation expenses, Account 587, were estimated by the utility on a trended basis using 10 years of recorded data from 1962, adjusted to a March 1, 1972 wage base.

As in other disputed expense amounts between staff and utility, the evidence in Account 587 was presented by staff witness Endres based upon recorded adjusted data for five years, 1968 through 1972. The data was trended to obtain 1974 estimates, adjusted to 1974 wage levels. Again, the utility urges that the trend line estimates of its witness should be accepted based upon actual 1973 experience adjusted to a March 1972 wage level. The staff witness Endres testified that customer gain would affect this account, and looking to the customer gain in 1970, 1971, and 1972, observed a higher gain than 1973 and 1974.

The staff estimated customer installations expense in Account 587 is below the utility estimated expense by $44,600. We will adopt the staff estimates for Account 587. Based upon the available evidence, we have accepted staff witness Endres' opinion that the most recent five years' data should be used in estimating expenses for this account.

b. Maintenance Expenses - Maintenance of Overhead Lines

Account 593, Maintenance of Overhead Lines, is a distribution expense account for the electric department which involve a major difference in estimates between the staff and the utility witnesses. Witness Endres for the Commission staff estimated test year expenses for this account at $3,047,000. The staff estimate was $608,600 lower than the utility estimate of $3,655,600. (See Exhibit 33, Table 5-A, page 5-2, line 18.)

The utility rebuttal exhibit presented a revised estimate by the utility. The utility stated that 1973 figures led to the conclusion that the original utility estimate was high for 1974. The utility suggests that the estimate of the staff should be increased by $300,000 to $3,347,000. The latter figure now appears as the proposed utility estimate for 1974 for this account.

As the staff brief states, witness Endres was concerned on the large difference he found in the distribution expense estimate for this account. Witness Endres indicated that in estimating the expense of Account 593, he would have to look at what the utility's operation is actually going to be. He stated that since 1973 construction did not come up to expectations, it is only reasonable to assume that a well-managed utility would not lay off good crews during periods of low construction. He felt that it was obvious that the utility had put crews out maintaining lines and felt there was a correlation in 1973 between a drop in construction and an increase in maintenance.

At this time it appears that maintenance expenses are higher than normal. However, as the staff witness indicated, the retention of experienced employees might be justified under the circumstances. We will adopt the utility estimate of $3,347,000.

To the extent that the analysis of staff witness Endres is correct, it is incumbent upon the utility to curtail expenses in this area in the future. Reduced construction activity should ultimately result in reduced expenses.

Rate Base - Electric Department

a. Tower Line Materials

The staff and the utility are in dispute as to the inclusion by the utility of transmission tower materials which were included by the utility in Account 154, Plant Materials and Operating Supplies, in the amount of $1,581,600. The staff would exclude the materials from rate base.

The staff position was presented by witness Lew. He testified that the tower line materials were purchased for specific projects and should not be accounted for in Account 154 but should have been charged directly to appropriate construction work orders. Witness Lew further testified that in order to classify property as property held for future use under Account 105, Electric Plant Held for Future Use, the tower materials would be owned and held for future use in electric service under a definite plan for such use. Witness Lew is under the impression that the bulk of the material was for a transmission line (San Onofre to Escondido) where construction was to start sometime in 1974.

Witness Houck for the staff also excluded the tower line material from rate base, and testified that the effect of the elimination would mean that the utility would not be able to earn a return on investment for the item. Witness Houck testified that it was his understanding that an unusually large purchase, such as $1,500,000 for tower steel, would usually be assigned directly to the job when purchased and would be earning interest during construction. He had a hard time visualizing this kind of an item in property held for future use, but stated that this was not within his field. Witness Houck did state that if the company had a work order open on a project and the material was assigned to a certain project, it would be allowed to earn interest during construction for a reasonable period of time.

Witness Parsley testified on the tower line materials on behalf of the utility. He testified that 65 towers held in the materials and supplies account can be used in 1980 in the planned expansion of the coastal and inland 230 kv transmission corridors running south from San Onofre. He stated that materials and supplies included in construction work in progress would include interest during construction on the material. However, projects have not been authorized so the utility has not charged a project with the materials. It was his view that the materials and supplies account should reflect tower material that will not be used until 1980.

The argument of the utility is that the material was not utilized because of a complaint case brought by the city of Escondido before this Commission (Case No. 8995) and the necessity of substituting aesthetic poles as a result of that case and the subsequent adoption of General Order No. 131 by the Commission. The position of the utility appears to be that since the tower material was not assigned to active work orders by matters outside the control of the utility, the tower material should be allowed to earn a return on the investment. The difficulty with accepting the utility position is that not only is the tower material unassigned to specific projects, but there is only the vaguest suggestion as to future use of the tower material, presumably by 1980.

Under these circumstances it is incumbent upon the utility to establish by evidence of record that it is reasonable to continue to hold the tower material at this time. There is no indication in the record that the tower materials cannot be disposed of or, in the alternative, that it is reasonable to hold the tower materials rather than to attempt to dispose of them. While we do not accept the staff point of view that management was imprudent in purchasing the tower material, the burden is upon the utility to show that this material should properly be included in rate base at this time. The inability to use the material arose from circumstances presumably outside the control of SDG&E. We cannot conclude from this that SDG&E ratepayers are now obligated to pay a return on the materials until the year 1980. Under the circumstances the tower materials estimated at $1,581,500 will be excluded from rate base at this time. Our determination does not preclude the utility from advancing further evidence on this issue in any future proceeding.

b. Fuel Oil in Storage

The utility and the staff disagree as to the amount allowable for fuel oil in storage. The staff brief alleges that it would be improper to adjust only one item of rate base just because that particular item happened to increase in cost. However, the problem appears to be one of evaluating fuel prices to reflect a weighted average balance of fuel in storage for test year 1974.

In order to reflect the actual dollars that the company has invested in the fuel oil in storage, we must price out the actual dollars invested in 1974. Staff witness Houck observed that if you priced out the inventory as of December 31, 1974, you would get a much higher inventory than the dollars that actually existed through the year. He indicated that since 1974 is the test year, possibly it is the actual dollars represented in the inventory for the year that should be used and not a repricing at a higher year-end price. In response to a question witness Houck recommended use of recorded monthly figures plus an estimate of what the company would expect to occur at current prices at the time of our decision. The current prices would be applied to future purchases reflected in the inventory for the test period to make an estimate for the remaining months.

The staff recommendation appears to be that the weighted average cost of fuel in inventory should be included in rate base. The cost of fuel oil and diesel fuel in storage included in rate base will be based upon the weighted cost of the fuel for the year. Staff witness Houck indicated the inventory calculation is basically a recorded figure for the months recorded in 1974. Future months will be estimated based upon current prices. The rate base is increased by $17,679,900 based on such 1974 costs.

Revenue from Rate Schedule A-6

The Secretary of Defense for the United States, appearing on behalf of federal agencies, presented testimony by witness Daniel J. Reed. The testimony of witness Reed dealt primarily with rate design. However, he examined in detail the test year forecast of A-6 sales to determine the profile of sales in each load block and in the terminal block. He concluded that the SDG&E forecast for the 1974 test year of estimated percentage sales in each of the four blocks resulted in an understatement in the percentage of sales in the initial blocks and an overstatement of sales in the tail block. He based this conclusion upon a comparison of estimates for the test year against recorded A-6 sales for the last twelve months. He examined the A-6 sales profile for recent historical periods and found they substantiated the profile for the recorded last twelve months. He recommended that for rate schedule A-6 the profile of sales in the four load blocks be based upon the actual sales to A-6 customers during the full year 1973.

Applying the percentages from the sales profile to the kilowatt-hour sales estimated for test year 1974, witness Reed established that revenues were understated by $243,175.

The evidence of witness Reed establishes that a detailed analysis was made which supports the position of the federal agencies on this issue. No substantial rebuttal evidence was presented indicating that the analysis of witness Reed was incorrect. Under the circumstances, it appears that the more accurate profile of sales in the load blocks for the A-6 customers for test year 1974 are those set forth in Exhibit 62, lines 8 through 11, column (c). The effect is an increase in adopted gross revenues for the test year of $243,175.

Adopted Results - Electric Department

Based upon our determinations, the adopted 1974 test year results of operations for the electric department are as set forth in Table 5. The adopted results reflect the increase in rate base resulting from the 1974 cost of fuel oil in storage. The gross annual revenue requirement at an 8.75 percent rate of return on the estimated test year is $196,564,200 excluding fuel clause adjustment revenues and expenses. Excluding fuel clause revenue, SDG&E requires a revenue increase of $7,588,800 annually in order to achieve a rate of return of 8.75 percent. The gross revenue increase authorized the electric department by our decision will include the above amount and an increase of $463,700 in fuel clause adjustment revenue to offset the increased cost of interdepartmental gas authorized in this decision. The electric department annual gross revenue increase authorized is $8,052,500, an increase of approximately 4½ percent.

The final rates authorized by this decision will include the rate changes resulting from the fuel adjustment clause. The fuel clause revenues presently include $243,300 in annual gross revenues which reflects our earlier interim increase in interdepartmental gas rates. The fuel clause revenue included in

TABLE 5

San Diego Gas & Electric Company

UTILITY AND ADOPTED SUMMARIES OF EARNINGS - 1974

Electric Department

Line No.	Item	Utility's Exh. 54A	Total Changes: Adopted Incl. Fuel Oil in Storage	Adopted Results	Adopted Results at: 8.75% Rate of Return
		(a)	(b)	(c)	(d)
		(Dollars in Thousands)			
1	Operating Revenues				
2	Sales to Customers	$187,990.3	$ -	$187,990.3	$195,526.5
3	Miscellaneous	1,011.7	-	1,011.7	1,037.7
4	Total Operating Revenues	189,002.0	-	189,002.0	196,564.2
5	Operating Expenses				
6	Fuel and Purchased Power	63,446.2	(237.9)	63,208.3	63,208.3
7	Production	8,450.9	(147.9)	8,303.0	8,303.0
8	Transmission	3,648.0	-	3,648.0	3,648.0
9	Distribution	9,658.2	(44.6)	9,613.6	9,613.6
10	Customer Acctg. & Coll.	5,031.2	(108.3)	4,922.9	4,936.7
11	Marketing	1,103.9	(181.4)	922.5	922.5
12	Administrative & General	13,822.5	(228.5)	13,594.0	13,747.5
13	Subtotal Expenses	105,160.9	(948.6)	104,212.3	104,379.6
14	Depreciation & Amortization	21,382.5	3.1	21,385.6	21,385.6
15	Ad Valorem Tax	11,535.7	-	11,535.7	11,535.7
16	Payroll Tax & Miscellaneous	1,032.4	-	1,032.4	1,032.4
17	State Franchise Tax	1,288.3	85.4	1,373.7	2,039.3
18	Federal Income Tax	3,543.4	(1,365.3)	2,178.1	4,751.0
19	Wage & Productivity Adj.	108.8	-	108.8	108.8
20	Total Operating Expenses	144,052.0	(2,225.4)	141,826.6	145,232.4
21	Net Operating Revenues	44,950.0	2,225.4	47,175.4	51,331.8
22	Deprec. Rate Base	570,544.2	16,098.4	586,642.6	586,642.6
23	Rate of Return	7.88%	0.16%	8.04%	8.75%

(Red Figure)

final rates for the electric department will include an additional amount of $463,700 in order to offset the costs to the electric department of the increase authorized in interdepartmental gas rates by this decision.

The rates adopted by this decision will increase gross revenues of the electric department by $7,588,800 in addition to interim rate increases already granted in these proceedings. The interim rates granted by Decision No. 82279 increased annual gross revenues by approximately $6,139,600 for the test year. Since the rates authorized by this decision will supersede the interim rates, the rates will be designed to produce a total increase in gross revenues of $13,728,400 annually.

Results of Operations - Steam Department

Table 6 sets forth the 1974 test year results of operations of the utility, staff, and our adopted results for the steam department. The adopted results are based upon our resolution of the staff and utility differences set forth in Exhibit 69, pages 11 and 12. The required gross revenue increase is $8,800.

Our determinations on the estimates in dispute have been discussed in detail on the items which are common to all departments. We have explained our reasons for adopting the staff estimates for the Administrative and General expenses on institutional advertising and contributions, dues, and donations. We have adopted the utility's estimates for payroll tax and the treatment of disallowed contributions in the calculation of federal income tax. However, we have adopted the staff's treatment of the state taxes paid deduction and the ITC determination in the calculation of federal income tax.

The remaining differences between the utility and the staff were substantially diminished when the utility accepted many staff estimates as set forth in SDG&E's Exhibits 56 and 56A.

TABLE 6

San Diego Gas & Electric Company

COMPARISON OF UTILITY AND STAFF SUMMARIES OF EARNINGS - 1974

Steam Department

Line No.	Item	Utility's Exhibit 56A Adjusted to Staff's Rev.* & Fuel Basis (a)	Changes Adopted (b)	Adopted Results* (c)	Adopted Results at 8.75% Rate of Return (d)
		(Dollars in Thousands)			
1	Operating Revenues				
2	From Sales to Customers	$476.8	$	$476.8	$485.6
3	Total Operating Revenues	476.8**		476.8**	485.6
4	Operating Expenses				
5	Fuel	251.4		251.4	251.4
6	Production	57.6		57.6	57.6
7	Distribution	41.8		41.8	41.8
8	Customer Acctg. & Coll.	1.6		1.6	1.6
9	Administrative & General	61.2	(0.7)	60.5	60.7
10	Subtotal Expenses	413.6	(.7)	412.9	413.1
11	Depreciation & Amortization	26.5	(.1)	26.4	26.4
12	Ad Valorem Tax	18.6	(.4)	18.2	18.2
13	Payroll Tax & Miscellaneous	8.0	-	8.0	8.0
14	State Franchise Tax	(2.0)	-	(2.0)	(1.2)
15	Federal Income Tax	(11.4)	.3	(11.1)	(7.4)
16	Wage & Productivity Adj.	-	-	-	-
17	Total Operating Expenses	453.3	(.9)	452.4	457.1
18	Net Operating Revenues	23.5	.9	24.4	28.5
19	Depreciated Rate Base	331.5	(5.8)	325.7	325.7
20	Rate of Return	7.09%	0.40%	7.49%	8.75%

(Red Figure)

* Steam rates, fuel price and mix at Decision 80432 levels.

** See Exhibit 70, sheet 5, column (a).

The utility stated that it accepted staff estimates to expedite rate relief (Exhibit 56, sheet 1 of 22, paragraph 2). However, the recommendation to use the staff estimates normally implies that such estimates are reasonable for ratemaking purposes. The staff estimates for depreciation and amortization expenses, ad valorem tax expense, and rate base will be adopted. The lower staff estimates reduce the revenue increase request by $500.

RATES

Rate Spread - Gas Department

Interdepartmental Gas

In our prior decision reviewing the rate structure of SDG&E, Decision No. 80432, the staff recommended that the rate for gas sold by the electrical department to the gas department should not be set at a price below the average cost of "basic" gas. The staff defined this to be the average cost of gas to the applicant at 100 percent load factor. The staff has repeated the recommendation in this proceeding. The utility and the city of San Diego urge that these Schedule G-54 rates should be as nearly equal to the incremental cost to gas as possible in order to prevent further deterioration of gas department earnings as supply of gas diminishes.

We recognize that there is some adverse impact on gas department earnings under the staff proposal when gas supply decreases. However, gas is a premium fuel at this time. Moreover, we have recognized a high cost increment of California LNG in the test year adopted results. We anticipate that any future gas supply will be at a higher cost than the historical cost of gas experienced by SDG&E. If we were to adopt the utility's position regarding rates for interdepartmental gas, G-54 rates would not reflect the steadily increasing cost of gas supply.

As the staff has pointed out, the additional California LNG gas will augment the gas available to the electric department and in fact generate income to the gas department at the G-54 rate. The staff recommendation on interdepartmental gas rates is adopted.

Retail Interruptible and Firm Industrial Service

Having adopted the staff's recommendation that the interdepartmental rates be established at the basic average cost of gas, we are persuaded that the staff's view of increases appropriate for the retail interruptible and firm industrial service is correct. The staff notes that there is a critical gas supply situation and that gas is a premium fuel when compared with alternate energy sources. Retail interruptible customers are expected to receive a higher level of satisfaction than the interdepartmental. There is no longer any justification to use pricing as an incentive for the consumption of natural gas. Under these circumstances the staff recommended that the percentage increase to retail interruptible be slightly greater than the increase to interdepartmental gas. Firm industrial customers will be assigned the same percentage increase as retail interruptible. Firm industrial will be priced closer to the general service class since both are firm service.

Schedule G-11, Domestic Service

The utility and the staff have agreed upon the transfer of all residential heating customers from G-11 to Schedules G-1 through G-4. The staff originally proposed that Schedule G-11 apply to customers who use gas space heating equipment only. This proposal involved the deletion of Special Conditions Nos. 2 and 3 which set forth gas usage allowed in determining a space heating customer. The basis for the staff's proposal was that special conditions had caused the transfer of small gas users to the G-11 rate, resulting in an increase for customers who were on the G-1 through G-4 rates. The transferring of small customers to a higher rate schedule was, in the staff's view, inconsistent with the Commission's action in recently authorizing special rates to small utility users. The utility reviewed the matter and suggested that all residential heating customers on the G-11 schedule be transferred to the G-1 through G-4 schedules. The staff stated that this proposal is consistent with the intent of the staff recommendation.

We adopt the utility's proposal as set forth in Exhibit 42. Under the Exhibit 42 proposal, the utility will transfer all residential heating customers from G-11 to G-1 through G-4. This will require additional revenue of $122,300 from the G-1 through G-4 schedules.

Zoning Criteria Change

The staff has recommended a small revision in the zoning criteria of SDG&E. Section A.7., the zoning criteria, is recommended for revision as follows:

> A.7. Customers whose service addresses are along the boundary of a rate zone or who are served directly (service conductor or service pipe) from distribution facilities located in or along the boundary, will be billed for gas or electric service under the lower rate schedules.

We accept the staff's revision. This change results in an additional revenue requirement of $6,300 in the general service class.

Miscellaneous Service

With regard to this service class, the staff recommendation will be followed. One-half of the over-all gas department percentage increase will be allocated to the facilities charges to Special Contracts 129, 146, 185, and 186. The average gas department percentage increase will be applied to Schedule G-91 and one and one-half times the gas department percentage increase will be applied to liquified natural gas-related Schedules GL-1 and GL-2, and Special Contracts 176 and 189.

Sales to Public Authorities and General Service

The average gas department percentage will be applied to other sales to public authorities. The remainder of the gas department increase will be assigned to general service customers. The result is revenue increases to customer classes as set forth in Table 7.

The gas department revenue increase is $1,994,100 annually, a 2.55 percent increase in gross revenues. The gas rates authorized by our order will also include all offset, tracking, and GEDA rate changes to and including October 5, 1974. The decisional gas rates will be base rates for the purchase gas adjustment clause authorized by this decision.

Rate Design for Tariff Schedules

The rate design adopted is as recommended by the staff. The first rate block for firm service schedules is increased by the percentage of the applicable service class. The balance of the required revenue from the class is obtained by dividing the sales into the balance of the required revenue, which results in a uniform cents-per-therm increase.

TABLE 7

San Diego Gas & Electric Company
Gas Department

ADOPTED REVENUE INCREASE

Class of Service	Revenue at Present Rates* (a)	Decision Revenues (b)	Increase M$ (c)	Increase % (d)
	(Dollars in Thousands)			
General Service	$61,978.6	$63,220.9	$1,242.3	2.00%
Firm Industrial	856.8	899.2	42.4	4.95
Other Sales to Public Authority	33.2	34.0	.8	2.41
Retail Interruptible	4,940.9	5,185.5	244.6	4.95
Interdepartmental	10,104.9	10,558.3	453.4	4.49
Miscellaneous Revenues	284.2	294.8	10.6	3.73
Totals	78,198.6	80,192.7	1,994.1	2.55

* Present rates are rates of 2-16-73 plus interim increase plus Southern California Gas Company Increase in A-53797.

For retail interruptible schedules, the service charge is increased by the applicable class percentage. The balance of the required revenue in the class is obtained by dividing the appropriate sales into the further required revenue to develop a uniform cents-per-therm increase.

Facility Charge to Gas Turbine Service

The staff has agreed to the utility's proposal to eliminate the facility charge to gas turbine service under Schedule G-54. This proposal will be adopted.

Revision of Rule 23

The staff has recommended the revision of Rule 23 in view of the shortage of gas supply and the decreased interruptible deliveries anticipated in the future. The company stated that 30 days would not be enough time to revise Rule 23 as recommended by the staff. Moreover, the proceedings in SoCal Application No. 53797 (Phase II) have not been concluded. It is anticipated that any revision of Rule 23 should be consistent with Commission determination in Phase II of the SoCal proceedings. The staff now proposes that a revision of Rule 23 be filed with the staff for review within thirty days after decision in SoCal's proceeding. We will adopt the staff proposal with modifications. SDG&E's recommended revision of Rule 23 shall be supplied to the staff thirty days after our decision in SoCal's Application No. 53797 (Phase II) when such decision establishes priority rights to gas on an interim or final basis. SDG&E shall file a revised Rule 23 within ninety days after any such decision in the SoCal proceeding.

Purchase Gas Adjustment Clause

SDG&E has requested authority to file a purchase gas adjustment clause (PGA) to replace the existing tracking procedures used to offset changes in the cost of gas. The staff agrees that a purchase gas adjustment procedure is appropriate at this time, but recommends certain conditions. We recently authorized the filing of a PGA by Southern California Gas Company (SoCal), applicant's principal gas supplier, by Decision No. 83160 dated July 17, 1974 in Application No. 53797. The reasons which supported authorization of the PGA for SoCal are set forth in detail in Decision No. 83160. Similar reasons support the use of the PGA for the gas department of SDG&E.

The PGA procedure will eliminate the necessity for frequent applications to extend tracking authorizations and will provide an orderly procedure to offset gas cost changes to applicant. The PGA procedure should reduce the demands on the staff time in reviewing and processing matters arising from gas cost changes. The alternative would be to continue the present procedures, which involve numerous applications to this Commission. The staff will continue to exercise control of rate changes under the PGA by review of requested PGA adjustments before they become effective. PGA adjustments will require Commission authorization before rate changes pursuant to such adjustment will become effective. The procedure will afford the staff an opportunity to review each filing and advise the Commission.

In order to provide the above procedures, we will adopt certain of the staff's recommended conditions in authorizing the use of the PGA. As recommended by the staff witness, filings will be made by SDG&E at least thirty days before the proposed effective date of a rate change. No change in the PGA shall become effective without Commission approval. SDG&E will file results of operations reports by April 15 of each year, such reports to set forth estimated operations for the ensuing year and recorded and adjusted operations for the prior year. A report on the reasonableness of the prices paid for gas purchases will be filed by April 15 of each year.

Refunds received by SDG&E from its suppliers as a result of an adjustment of prices paid for gas included as PGA charges shall be flowed through to SDG&E customers, such refunds to include interest at 7 percent. SDG&E may accumulate such amounts for refunding until they total $1,000,000 or more before making the refunds.

The PGA shall be revised no more than six times each year. This provision is consistent with the PGA authorized SoCal. Any PGA filing must reflect a change in the weighted average unit cost of gas equal to or greater than 0.024 cents per M^2Btu.

The PGA initially established shall be prepared by SDG&E and filed with the Commission. This PGA shall be subject to the Commission's review and approval prior to becoming effective. The PGA clause shall set forth the conditions adopted by our decision.

Should SDG&E desire to incorporate new increments of gas supply into the PGA, SDG&E shall separately state its request to include such new supply. Such request shall set forth sufficient facts to advise the Commission of the reasonableness of the inclusion of the new gas supply in the PGA. Such facts shall include the cost of the new supply including the cost actually proposed to be included in the PGA filing and anticipated future cost under the terms of the acquisition of such new supply. SDG&E shall advise the Commission of the actual terms under which the new supply was secured.

Conclusions on Gas Rates

In adopting the staff's recommendations on gas rates, we have rejected rate proposals of the city of San Diego regarding requested rates in the city. San Diego requests that SDG&E rate structure be altered to more closely match the rate blocking and zoning in other large California cities. Such proposals are directly contrary to our view that under current conditions, rate design should result in more level rates. The San Diego proposals would result in a return to lower rates in the terminal blocks, and lower costs to larger consumers of gas. This result is not appropriate under present conditions of gas supply and costs. The fact is that certain customer classes were granted preferential prices in the past and that continuation of such preferential treatment is no longer justified.

Rate Spread - Electric Department

General Discussion

The major parties in these proceedings have indicated substantial agreement on the initial rate spread approach of the Commission's staff on electrical department rates. The staff witness recommended that the revenue requirements based upon the test year 1974 results of operations be apportioned to each customer group on a uniform percentage basis. At this point all parties appear to be in agreement. The interim increases granted the electric department in these proceedings will be recomputed and spread on a percentage increase basis and the interim increases will be superseded by the rates authorized by our decision. As discussed earlier in this opinion, both the interim and final increases in interdepartmental gas rates will be included in the fuel adjustment clause factor which will be added to the rate spread to establish new base rates as of October 5, 1974.

The dispute between the parties arises when consideration is given to spreading the revenue increase to the schedules within the customer class and within the schedules of any particular customer group by increasing fixed charges and cents per kilowatt-hour rates in the rate blocks. The staff witness recommended that after determining the revenue requirements from each customer group on a uniform percentage basis, the rate increase be spread to the schedules within the customer groups by increasing the fixed charges by the amount of the class percentage increases and increasing each rate block the class average cents per kilowatt-hour increase required. There does not appear to be any substantial dispute by the utility to the staff witness's proposals.

Both the utility and the staff agree that there are certain rate schedules where it is necessary to continue to use the uniform percentage basis rather than the uniform cents per kilowatt-hour. The staff is in agreement with the utility's position in this regard with the exception of Schedule H-1. The staff is prepared, based upon the rate spread data available on Schedule H-1, to design rates on the uniform cents per kilowatt-hour basis for this schedule.

The city of San Diego proposes lower street lighting rates than the staff, additional rate zones within the San Diego city limits, and additional rate blocking. The City argues that its requested new zones and additional rate blocks should be adopted in order to treat San Diego as the Commission treats the cities of San Francisco, Los Angeles, and Long Beach. San Diego would shift the revenue requirements resulting from adoption of lower rates within the City to other schedules of the utility.

The brief filed on behalf of the federal agencies indicates a major concern with the rate structure proposed by the staff for the A-5 and A-6 customers. The brief reviews in detail the evidence on cost of service and rate design, as applicable to the proposed rate structure for the A-5 and A-6 customers. The argument is made that while the company's cost of service studies may have infirmities, they are better than nothing and once accepted in relation to costs between classes of customers, they are not invalid in relation to the distribution of costs within a rate. Based on the available cost studies, the federal agencies conclude that the increase in tail blocks in the A-5 and A-6 classes on a uniform cents per kilowatt-hour basis will result in a shortfall recovery of profits under conservation efforts from customers. The answer indicated by the federal agencies is to prevent a shortfall in earnings by assigning fixed costs and rate of return elements in the initial blocks and reducing terminal blocks to variable costs.

Cost of Service Studies

A threshhold question arises from the lack of agreement regarding use of the cost of service information available to the Commission regarding the electrical department. Staff witness Endres presented the staff recommendations on rate design for the electrical department of SDG&E. Witness Endres recommended that the utility be ordered to collect additional data on customer group load characteristics for the use of the preparation of cost allocations studies by jurisdictional customer groups for future proceedings. He stated that the cost allocations study available from the utility had insufficient data on the load factors for the customer groups, and he gave the study little weight for this reason.

The SDG&E position is that cost allocations studies are of limited value in the rate design and rate allocation areas as there are other factors which affect the spread of rates between customers and the design of rates for a particular rate schedule. Moreover, SDG&E argues that the only way the information requested by the staff could be obtained would be the installation of digital pulse recorders which would cost approximately $1,000 per customer and SDG&E argues that that cost is excessive.

The position of the federal agencies is that complete and thorough data with regard to the cost which various classes of customers impose upon the utility is of extreme value to the Commission and to any decision maker in reaching an informed decision about which rates and charges are just and reasonable between classes of customers and between customers within a class. The federal agencies strongly support the staff recommendation.

It is a fact that cost of service is but one factor considered in attempting to design rates. In discharging our duty to establish rates which are just, reasonable, and sufficient, the Commission will also consider value of service, adequacy of service, history, and public benefit. A detailed discussion of rate spread considerations has recently been set forth in our Decision No. 81919 dated September 25, 1973 in Application No. 53488 (Southern California Edison Company). We agree with the position of the federal agencies and the staff. Without adequate cost of service information an informed decision becomes increasingly difficult. In this case, as in past decisions, the cost of service considerations may be subordinate to other factors. However, without adequate cost of service information, it will become increasingly difficult for the Commission to make a reasoned judgment in support of authorized rates. The staff recommendation will be followed.

Increases to Customer Classes

As noted above, there is general agreement regarding the staff's recommendation that the percentage increase in electric department revenues should be applied uniformly to the customer classes. In adopting this recommendation, the uniform percentage will include the revenues resulting from the interim increase granted the electric department in these proceedings.

The uniform percentage increase is spread to the customer classes with the exception of Resale and Other Sales to Public Authorities. The utility requested a greater than average percentage increase to large power customers to compensate for the fact that fuel clause revenue is not collected from the California Department of Water Resources and resale customers. The staff witness asserted that these costs should be recovered from the applicable customer classes by renegotiation of the contracts with the customers.

The authorized rates increase gross revenues of the electric department approximately 7.5 percent, an increase of $13,728,400. This amount includes the interim increase authorized by our earlier Decision No. 82279. Rate increases authorized on adopted revenue requirements by that decision will be spread to the customer classes as set forth in Table 8.

In adopting the staff recommended rate design we will follow the staff's recommendation that the fuel cost adjustment be reduced to zero. The revenue requirement and rates developed above reflect fossil fuel requirements at Decisions Nos. 80432 and 81517 fossil fuel prices and mix. To the rates developed as a result of the above revenue requirement, we shall add the current fuel adjustment. The interim and final interdepartmental gas rate increases authorized in this proceeding are included in the fuel clause adjustment.

We have adopted the staff's recommended change in zoning criteria for the gas department. The same change to Section A.7. of the zoning criteria will be adopted for the electrical department. This change will apply to cases where the center line of a road or street establishes a rate zone boundary and will benefit certain customers served by facilities in and along the boundary. An additional revenue requirement of $24,600 will be authorized for this change.

The electric rates set forth in this decision, Appendix C, become base rates for 1974. The fuel clause adjustment becomes zero. The 1974 fossil fuel prices and mix shall be at the October 5, 1974 prices and mix as set forth in Appendix E.

TABLE 8

San Diego Gas & Electric Company
Electric Department

ADOPTED REVENUE INCREASE

1974

Class of Service	Adjusted Revenue at Present Rates∅ (a)	Decision Revenues∅ (b)	Revenue Increase Amount (c)	Revenue Increase % (d)
	(Dollars in Thousands)			
Domestic	$ 78,744.5	$ 84,707.1	$ 5,962.6	7.57%
General Service - Regular	64,251.6	69,123.1	4,871.5	7.58
General Service - Large	28,107.7	30,240.8	2,133.1	7.59
General Power	4,450.9	4,788.3	337.4	7.58
Agricultural Power	2,709.1	2,914.4	205.3	7.58
Street Lighting	2,888.7	3,107.7	219.0	7.58
Resale	19.4	19.4	-	-
Other Sales to Public Authorities	652.2	652.2	-	-
Subtotal	181,824.1	195,553.0	13,728.9	7.55
Zoning Change	-	(26.5)	(26.5)	-
Miscellaneous	1,011.7	1,037.7	26.0	2.57
Total	182,835.8	196,564.2	13,728.4	7.51

(Red Figure)

∅ Excluding Fuel Cost Adjustment Revenues.

Rate Spread Within Customer Classes

The staff witness on electric rates stated that due to the present shortage and unavailability of fossil fuel and the need to conserve energy as well as curtail usage, all rates should be designed to provide greater increases to larger users within a class. The staff recommendation was that the fixed charges of rates should be increased by approximately the customer group average percentage increase. The remaining revenue increase to each customer group and the increase from the fuel adjustment clause will be spread to each rate block on an average cents per kilowatt-hour basis. The exceptions to this rate spread are general power, agriculture power, street lighting, outdoor lighting, and A-ME2 schedules where rates will be increased by the customer group average percentage plus the average energy charge per kilowatt-hour resulting from the fossil fuel cost increase.

The staff method develops the final decisional rates by adding the 1974 fossil fuel costs in excess of Decisions Nos. 80432 and 81517 fossil fuel prices and mix to the rates developed above. Both the city of San Diego and the federal agencies object to the staff proposed rate spread.

Rate Proposals of the City of San Diego

San Diego proposes to add an additional zone for gas and electric customers in order to put customers in San Diego's central portion into a special rate zone. Since this special zone would, under San Diego's proposal, have lower rates the customers outside the special zone would receive higher rate increases to supply the revenue required from the customer class as a whole.

San Diego also proposes additional rate blocks and substantially lower rates in the tail blocks. Exhibit 72, Sheet E-1 may be compared with Exhibit 3, Chapter 14, Table 14-A, Sheet 3 of 11. The effect of San Diego's rate proposals would be to benefit the large user within each class.

Absent adequate cost studies, it is difficult to see a factual basis for the rate structure proposed by San Diego. San Diego does contend that the rates it proposes are cost-related. Substantial evidence to the contrary exists. Witness Reed, appearing on behalf of the federal agencies, established that the available cost studies supported the uniform cents per kilowatt-hour addition to each rate block for 97 percent of the SDG&E customers which are not demand-metered. Staff witness Endres testified that he did not have an adequate cost of service study showing the cost to serve customers into the tail blocks. San Diego attempted to support its rate proposals by stating that its proposal is similar to the rate blocking and zoning presently available to utility customers in San Francisco, Los Angeles, and Long Beach.

The City's suggestion that SDG&E rate structure should be changed to match rate structures of utilities serving the cities of Long Beach, Los Angeles, and San Francisco does not supply this Commission with any rational support for such action. Absent evidence of substantial comparability as to utility costs and as to service areas served by other utilities in the State, the argument would appear to be one which could be applied in support of exactly the opposite conclusion: the rate zoning, blocking, and zone levels of SDG&E should be applied to the other large cities in the State of California. Moreover, the proposition that the present rate structure discriminates against customers of SDG&E in the city of San Diego, when such customers are compared with utility ratepayers in the other large cities in the Stare of California, overlooks the failure of an evidentiary showing in support of the proposed rate changes. If we were to adopt the proposal of the city of San Diego, it would appear that customers of SDG&E outside of the special zone to be authorized in the city of San Diego would necessarily receive higher rates in order to supply the revenue required from the customer class. The evidence would not support such discriminatory treatment and it is questionable whether such rate changes would be reasonable treatment of all customers of SDG&E in the particular customer classes.

The city of San Diego objects to the continuation of the franchise fee surcharge presently added to the bills of all SDG&E customers in the city. The surcharge reflects the amount of franchise fees paid by SDG&E to the city which are in excess of the rate paid in other jurisdictions. In our view, the franchise fee in excess of the system rate represents a charge imposed by San Diego for the benefit of the city and its residents. Ratepayers outside the city should not pay in their utility rates moneys to support the local government of San Diego. The city argues that its evidence supports the proposition that ad valorem taxes paid in San Diego are lower than the average amount of such tax imposed on SDG&E by other jurisdictions. San Diego would conclude that their higher franchise fees are more than offset by lower ad valorem taxes and the surcharge should be terminated.

We are not persuaded that we should view the ad valorem taxes is separate jurisdictions as substantially similar to the higher franchise fees imposed by San Diego. The ad valorem tax rate is applied to all property within the jurisdiction authorized to impose the tax. It is reasonable to assume that local governmental officials are subject to some constraints in the imposition of taxes applicable to all their residents. The higher franchise fee appears more analogous to the imposition of a utility user's tax, which is imposed by a local governmental entity on the ratepayers within its jurisdiction. To allow local agencies to spread local tax burdens outside of their respective jurisdictions would not be reasonable treatment of all SDG&E ratepayers.

Rate Proposals of the Federal Agencies

The Secretary of Defense of the United States appeared on behalf of all the executive agencies of the United States. The federal agencies present substantial objections to the proposed rate design. Their major interest, as indicated by their brief, relates to the rates proposed for the general service large customer class.

A basic premise of the federal agencies is that rate blocking should track the costs incurred by the company in providing service. Witness Daniel J. Reed appeared for the federal agencies and presented testimony and exhibits in support of rate schedules for the A-5 and A-6 customers. The proposed rate schedules of witness Reed, set forth in Exhibit 44 at pages 34 and 38, may be compared with the proposed A-5 and A-6 schedules of the utility set forth in Exhibit 3, Table 14-A, at pages 14-3 and 14-4. The staff's exhibit does not set forth a recommended rate design at 100 percent of the revenue request because the staff design results in almost the same rates as the utility.

A comparison of the rates proposed by witness Reed with the utility's proposed rates establishes that he would provide substantially lower rates in the tail blocks for the

A-5 and A-6 customers. This is directly contrary to the rate design recommended by staff witness Erwin Endres, who recommended that rates be designed to maintain the greatest increases for the large users within each class.

The staff rate design is based on the necessity of encouraging conservation efforts under the present shortages in fossil fuel supply. Witness Endres stated that his recommended rate design is intended to encourage conservation of energy as measured by kilowatt-hour consumption. The federal agencies concede that under general economic theory, all goods and services should be price elastic. However, they point out that little is known about the price level at which elasticity will be experienced. The federal agencies argue that their proposed A-5 and A-6 rates with substantially lower tail block rates will encourage demand-metered customers to control and/or moderate their demand, dampening the growth of generating capacity.

The federal agencies agree that the fuel adjustment clause should reflect a cost increase by applying a uniform charge per kilowatt-hour to all classes of customers. However, two arguments are made relative to the operation of the fuel clause. The first proposition is that the burning of no-load fuel is lower to A-6 customers when contrasted with the delivery to domestic customers. The second element is that fuel cost is incurred at the point of generation and not at the point of sale. The argument is that if the cost to generate electricity for A-6 customers is lower than the cost to generate the same amount of delivered electricity for domestic customers, the fuel clause factor should be less to the A-6 customers. The federal agencies argue that large customers should not be burdened with more than their fair share of fuel cost. The federal agencies also point out that the operation of the fuel clause increases results in substantially larger percentage increases to general-service-large customers than to other classes. This result occurs because the classes of customers contrasted with the general service large customers were paying a substantially higher rate per kilowatt-hour before the fuel clause adjustment increases were applied. The federal agencies assume that the advantageous rates offered the general-service-large customer class should be maintained in relationship to the other customer classes. As the staff has pointed out, such historical rate structure is not consistent with the necessity of conservation today.

We agree with the position of the federal agencies that level rates are not without problems. Conservation by customers under level rates obviously can have a sharp adverse impact on profits. Moreover, level rates may reduce the economic incentive to customers to maintain high load factors. These problems discussed in detail in the brief of the federal agencies cannot be easily disposed of. However, the necessity of recognizing substantial fuel oil and gas cost increases requires substantial changes in the rate structures of the more favored users of electricity.

We have recently issued an order instituting an investigation into electric utility rate structures, Case No. 9804 dated October 1, 1974. Pursuant to Assembly Concurrent Resolution No. 192, the Commission investigation includes consideration of placing all future rate increases in the tail block of the existing decreasing block pricing structure so that an increase in block pricing structure will be achieved. Another proposal is consideration of inverting the rate structure to achieve immediately increasing block pricing. In this proceeding there are no viable cost studies to support rate design within the customer classes in the opinion of the staff rate witness. Moreover, the staff recommended rate spreads will still encourage large users to limit their demand and improve their load factor in order to secure benefits of the declining rates available as usage goes into the tail block.

The federal agencies concede in their brief that their proposed rate design for A-5 and A-6 customers will result in less saving by the U.S. Navy as a result of conservation efforts. The point is that the staff recommended rates will discourage use of electricity and encourage conservation. Under the circumstances, the rate design recommendations of the federal agencies will not be adopted.

Findings

1. A reasonable rate of return to be applied to SDG&E's jurisdictional rate base is 8.75 percent.

2. For the test year 1974, a reasonable estimate of SDG&E's gas department operations are the adopted estimates set forth in Table 3. Table 3 estimated revenues and expenses exclude tracking, GEDA, and offset rate changes authorized to reflect changes in the cost of gas after February 16, 1973.

3. For the test year 1974, reasonable estimates of SDG&E's electric and steam department operations are the adopted estimates in Tables 5 (electric department) and 6 (steam department). The revenues and expenses set forth in Tables 3 and 5 exclude rate changes and related costs from the operation of the fuel adjustment clause.

4. Based upon the adopted estimates, SDG&E gas department revenues should be increased by $1,994,100 annually, an increase of 2.55% in gross revenues.

5. Base rates for the gas department of SDG&E should be authorized as set forth in Appendix B. The authorized gas rates increase annual gas department revenues by $1,994,100 and include all offset, GEDA, and tracking rate changes authorized and established after February 16, 1973 to and including October 5, 1974.

6. Present procedures used to track gas cost changes have resulted in numerous separate proceedings before the Commission. A filed purchase gas adjustment (PGA) clause applicable to commodity rates in all filed gas rate schedules will improve the present procedures. SDG&E should file a PGA, which contains the conditions set forth in our decision. The PGA should become effective only after Commission authorization by resolution.

7. SDG&E should revise Section A.7. of its zoning criteria to provide as follows:

> A.7. Customers whose service addresses are along the boundary of a rate zone or who are served directly (service conductor or service pipe) from distribution facilities located in or along the boundary, will be billed for gas or electric service under the lower of the rate schedules.

8. SDG&E should revise its tariff provisions to make gas service available to domestic space heating customers on Domestic Schedules Nos. G-1 through G-4 rather than on Schedule No. G-11.

9. SDG&E should revise its Tariff Rule No. 23, Shortage of Gas Supply and Interruption of Delivery, within 90 days after the issuance of an interim or final decision establishing priority rights to gas supply in Southern California Gas Company's Application No. 53797, Phase II proceedings.

10. Based upon the adopted estimates, SDG&E electric department revenues should be increased $8,052,400 annually, an increase of approximately 4½ percent in gross revenues. That increase in annual revenues includes $463,700 which reflects the revenue required to offset increased costs of interdepartmental gas authorized by this decision. This revenue requirement will be included in the fuel clause adjustment to establish base rates.

11. Base rates for the electric department of SDG&E should be authorized as set forth in Appendix C. Those rates increase electric department gross revenues by $8,052,400 annually and include all authorized fuel clause adjustment rate changes to and including October 5, 1974.

12. Base rates for the steam department of SDG&E should be authorized as set forth in Appendix D. Those rates increase steam department revenues by $8,800 annually, an increase in gross revenues of approximately 1.85 percent. The rates set forth in Appendix D include all fuel clause adjustment rate changes to and including October 5, 1974.

13. The fuel costs and mix for the fuel adjustment clause at base rates are set forth in Appendix E. The fuel adjustment is reduced to zero on the date the rates authorized by this decision go into effect.

14. There is no evidence that the estimated expenses of SDG&E for contributions to employees' pensions are unreasonable.

15. Current conditions regarding fuel cost and supply require that customers of SDG&E curtail usage and conserve energy. The rates established by this decision establish greater percentage increases for larger users of energy, and should encourage conservation.

16. The rates set forth in Appendices B, C, and D are just and reasonable; and present rates and charges which differ from those prescribed by this decision are for the future unjust and unreasonable.

17. The Commission requires and needs adequate cost of service studies in order to evaluate proposed rates. The Commission staff will need data on customer group load characteristics which provide accurate load factors for customer groups. SDG&E should make such studies as are necessary to obtain such data.

18. This decision considers, as Phase I, the requests set forth in the three applications as originally filed, and does not consider or dispose of the requests set forth in the amended applications (Phase II).

Conclusion

The three original applications should be granted to the extent set forth in the following order, and the original applications are in all other respects denied.

INTERIM ORDER

IT IS ORDERED that:

1. San Diego Gas & Electric Company is authorized to file with this Commission after the effective date of this order, in conformity with the provisions of General Order No. 96-A, revised tariff schedules with rates, charges, and conditions modified as set forth in Appendix B (Gas), Appendix C (Electric), and Appendix D (Steam), each of which is attached to this order, and on not less than five days' notice to the Commission and to the public, to make such revised tariffs effective five days after filing.

2. Authority to add a purchase gas adjustment clause is granted. Applicant shall file a PGA in conformity with our finding No. 6. The PGA shall not become effective until the Commission approves the PGA by resolution.

3. Applicant shall obtain data on electric customer group load characteristics and determine accurate load factors for the customer groups. Within 30 days of the effective date of this decision applicant shall file an initial written report setting forth the time required to obtain necessary data and prepare a report determining accurate load factors for the customer groups. Such initial report shall outline the methods applicant proposes to use to develop the data, including the equipment and sampling methods to be utilized.

4. Applicant shall revise Section A.7. of its zoning criteria as set forth in finding No. 7 within 90 days of the effective date of this decision.

5. Applicant shall revise its tariff provisions in order to make gas service available to all domestic space heating customers on Domestic Schedules Nos. G-1 through G-4 rather than on Schedule No. G-11. Such revised tariffs shall be filed within 30 days of the effective date of this decision.

6. Applicant shall file a revised Tariff Rule 23 within 90 days after issuance of an interim or final decision establishing priority rights to gas supply in Application No. 53797, Phase II. Such revised rule shall adopt provisions substantially similar to Southern California Gas Company's Rule No. 23.

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

Dated at San Francisco, California, this 29th day of OCTOBER, 1974.

Vernon L. Sturgeon
President
William Symons Jr.
Thomas Moran
D. W. Holmes
Robert E. McFarland
Commissioners

APPENDIX A

APPEARANCES

Applicant: Chickering & Gregory, by C. Hayden Ames, Donald J. Richardson, Jr., and Allan J. Thompson, Attorneys at Law; Gordon Pearce, Attorney at Law; and John H. Woy.

Interested Parties: Colonel Frank J. Dorsey, U.S. Army, and Charles J. Mackres, Office of Judge Advocate, for Department of Defense and other Executive Agencies of the United States of America; John Witt, City Attorney, Robert Logan, Deputy City Attorney, and Manley W. Edwards, for City of San Diego; Dave Johnson, for Conservation Committee, Sierra Club, San Diego Chapter; and David B. Follett, Attorney at Law, for Southern California Gas Company.

Commission Staff: Elinore C. Morgan, Attorney at Law, Robert C. Moeck, and Kenneth K. Chew.

RATES - SAN DIEGO GAS & ELECTRIC COMPANY
GAS DEPARTMENT

Applicant's rates, charges and conditions are changed to the level or extent set forth in this appendix.

Rates authorized include gas cost offsets and GEDA offsets through October 1, 1974.

GENERAL NATURAL GAS SERVICE

RATES

	Per Meter Per Month Schedule No.			
Commodity Charge:	G-1	G-2	G-3	G-4
First 2 therms or less	$ 1.65000	$ 1.70295	$ 1.80885	$ 1.91475
Next 28 therms, per therm	15.967¢	16.484¢	17.015¢	17.563
Next 70 therms, per therm	13.246	13.441	13.637	13.931
Next 100 therms, per therm	11.777	11.777	11.777	11.777
Over 200 therms, per therm	11.190	11.190	11.190	11.190

Commodity Charge:	G-4 Rate (B)
First 2 therms, or less	1.91475
Next 28 therms, per therm	17.563
Over 30 therms, per therm	13.931

RATES - SAN DIEGO GAS & ELECTRIC COMPANY
GAS DEPARTMENT

Schedule No. G-11

SPACE HEATING NATURAL GAS SERVICE

APPLICABILITY

Applicable to natural gas service to commercial or industrial customers where use is primarily for space heating.

RATES

Commodity Charge:	Per Meter Per Month
First 4 therms, or less	
Winter months, December-May	$ 3.32118
Summer months, June-November, per therm	17.946¢
Next 26 therms, per therm	17.946
Next 70 therms, per therm	15.499
Next 100 therms, per therm	13.247
Over 200 therms, per therm	12.580

Minimum Charge:

$3.32 per meter per month - winter months, December-May.

SPECIAL CONDITIONS

Delete Special Condition No. 2.
Change Special Condition No. 3 to Special Condition No. 2.

RATES - SAN DIEGO GAS & ELECTRIC COMPANY
GAS DEPARTMENT

Schedule No. G-40

FIRM INDUSTRIAL NATURAL GAS SERVICE

RATES

Commodity Charge:	Per Meter Per Month
First 1,600 therms or less	$184.037
Next 1,600 therms, per therm	10.275¢
Next 7,400 therms, per therm	10.080
Over 10,600 therms, per therm	9.786
Minimum Charge:	$184.04

Schedule No. G-50

INTERRUPTIBLE NATURAL GAS SERVICE

RATES

	Per Meter Per Month
Service Charge:	$24.26
Commodity Charge: (To be added to the Service Charge)	
First 2,000 therms, per therm	8.818¢
Next 5,000 therms, per therm	8.344
Next 25,000 therms, per therm	8.074
Next 32,000 therms, per therm	7.915
Next 42,000 therms, per therm	7.776
Over 106,000 therms, per therm	7.571

Minimum Charge:

Increase the minimum charge for the billing months of March through November to $123. Increase the total charges for the nine minimum charge months of the contract year to $1,107.

RATES - SAN DIEGO GAS & ELECTRIC COMPANY
GAS DEPARTMENT

Schedule No. G-51

INTERRUPTIBLE NATURAL GAS SERVICE

RATES	Per Meter Per Month
Service Charge:	$32.35
Commodity Charge: (To be added to Service Charge)	
First 2,000 therms, per therm	8.493¢
Next 5,000 therms, per therm	8.101
Next 25,000 therms, per therm	7.785
Next 74,000 therms, per therm	7.599
Over 106,000 therms, per therm	7.423

Minimum Charge:

Increase the minimum charge for the billing months of March through November to $3,440. Increase the total charges for the nine minumum charge months of the contract year to $30,960.

Schedule No. G-54

INTERRUPTIBLE SERVICE TO UTILITY ELECTRIC GENERATING STATIONS

RATES	¢/MMBtu
Commodity Charge:	
Per MMBtu per month	69.287¢

SPECIAL CONDITIONS

Revise Special Condition 2 to read as follows:

2. Gas Turbine Generators
Utility-owned gas turbine generators may be served under this schedule.

RATES - SAN DIEGO GAS & ELECTRIC COMPANY
GAS DEPARTMENT

Schedule No. G-91

SERVICE ESTABLISHMENT CHARGES

RATE

For each establishment, supersedure, or re-establishment of gas service $1.15

SPECIAL CONDITION 2

Increase the additional charge stated in this Special Condition to $3.60

Schedule No. GL-1 (Borrego)

SERVICE FROM LIQUEFIED NATURAL GAS FACILITIES

RATES

The charges as determined under a regularly filed schedule applicable to the service rendered, plus a Facility Charge as follows:

Domestic Use	$7.18 per family accomodation per month.
Non-Domestic Use . . .	3.56¢ per month per 1,000 Btu per hour of connected load.

RATES - SAN DIEGO GAS & ELECTRIC COMPANY
GAS DEPARTMENT

Schedule No. GL-2 (Alpine)

SERVICE FROM LIQUEFIED NATURAL GAS FACILITIES

RATES

The charges as determined under a regularly filed schedule applicable to the service rendered, plus a Facility Charge as follows:

Domestic Use . . . . . $5.16 per family accomodation per month.

Non-Domestic Use . . . 4.57¢ per month per 1,000 BTU per hour of connected load.

SPECIAL CONTRACTS 129 AND 146

Increase the annual additional charge percentage for use of special facilities to 16.1% per year.

SPECIAL CONTRACT 176

1. Increase the monthly charge for each of the 174 unmetered gas lamps to $6.34.

2. Increase the monthly charge for the four metered gas lamps to $38.40.

3. Increase the monthly facility charge specified in the contract for each family accommodation to the same level as Schedule No. GL-1.

SPECIAL CONTRACT 185

Increase the annual additional charge percentage for use of special facilities to 17.7%.

RATES - SAN DIEGO GAS & ELECTRIC COMPANY
GAS DEPARTMENT

SPECIAL CONTRACT 186

Increase the Commodity Charge for natural gas service to 9.737¢ per therm. Increase the annual facilities charge to $33.910.

SPECIAL CONTRACT 189

Increase the monthly facility charge specified in the contract for each family accommodation to the same level as Schedule No. GL-2.

RATES - SAN DIEGO GAS & ELECTRIC COMPANY

Applicant's rates, charges and conditions are changed to the level or extent set forth in this appendix.

SCHEDULES A-1, A-2. A-3 and A-4

RATES

	Per Meter Per Month			
	Schedule No.			
	A-1	A-2	A-3	A-4
Customer Charge	$0.86	$1.02	$1.18	$1.35
Energy Charge (to be added to Customer Charge):				
First 100 kwhr, per kwhr	5.633¢	5.903¢	6.293¢	6.773¢
Next 400 kwhr, per kwhr	4.773¢	4.903¢	5.103¢	5.383¢
Next 1,000 kwhr, per kwhr	4.223¢	4.313¢	4.463¢	4.743¢
Next 1,500 kwhr, per kwhr	3.823¢	3.823¢	3.823¢	3.823¢
Next 2,000 kwhr, per kwhr	3.203¢	3.203¢	3.203¢	3.203¢
All Energy in Excess of 5,000 kwhr per month:				
First 100 kwhr per kw of billing demand, per kwhr	3.203¢	3.203¢	3.203¢	3.203¢
Next 100 kwhr per kw of billing demand, per kwhr	2.803¢	2.803¢	2.803¢	2.803¢
Next 100 kwhr per kw of billing demand, per kwhr	2.503¢	2.503¢	2.503¢	2.503¢
All excess kwhr, per kwhr	2.303¢	2.303¢	2.303¢	2.303¢

Minimum Charge

The minimum charge shall be the customer charge, except where loads listed below are served, in which case the following amounts will be added to the customer charge:

1. For air heating load, 69¢ per month per kilowatt of aggregate capacity in excess of 3 kilowatts of connected load.
2. For power load, $1.38 per month per horsepower of aggregate capacity in excess of 3 horsepower of connected load.
3. For seasonal or intermittent loads, as provided in Special Condition 7.

Fuel Cost Adjustment

The charges as determined above are subject to a fuel cost adjustment as provided for in Section 9 of the Preliminary Statement. The fuel cost adjustment billing factor set forth therein will be applied to all kilowatt-hours billed under this schedule.

SCHEDULES A-1, A-2, A-3 and A-4 (Continued)

SPECIAL CONDITIONS

1. Add the following to Special Condition 4 of each schedule:

   "For maximum demands occurring between the hours of 10 p.m. to 7 a.m. of the following day, only 60 percent of such maximum demand shall be considered, provided the customer has requested and the utility has installed a recording demand meter. When a recording demand meter has been installed at the customer's request, the billing demand shall in no case be less than the limits described in (a) or (c) above, or 80 percent of the highest billing demand registered during the preceding eleven months."

2. Revise Special Condition 7 of each schedule to increase the charge per kilowatt from 64¢ to 69¢ per month.

3. Revise Special Condition 9 of each schedule to change the caption from "Standby Service" to "Miscellaneous."

SCHEDULE A-MEZ

RATES

	Per Meter Per Month
First 40 kwhr, per kwhr	12.225¢
Next 60 kwhr, per kwhr	8.482
Next 900 kwhr, per kwhr	4.738
All excess kwhr, per kwhr	3.737

Minimum Charge

The monthly minimum charge shall be $2.25 where 3 kva or less of transformer capacity is required and $4.12 where 5 kva of transformer capacity is required.

Fuel Cost Adjustment:

The charges as determined above are subject to a fuel cost adjustment as provided for in Section 9 of the Preliminary Statement. The fuel cost adjustment billing factor set forth therein will be applied to all kilowatt-hours billed under this schedule.

SCHEDULE A-5

RATES

Energy Charge	Per Meter Per Month
First 6,000 kwhr or less	$ 265.00
All Energy in Excess of 6,000 kwhr per month:	
First 100 kwhr per kw of billing demand, per kwhr . .	3.188¢
Next 100 kwhr per kw of billing demand, per kwhr . .	2.668¢
Next 100 kwhr per kw of billing demand, per kwhr . .	2.198¢
All excess kwhr, per kwhr	1.998¢

Minimum Charge

The monthly minimum charge shall be $265.00 but not less than $1.18 per kw of billing demand.

Fuel Cost Adjustment

The charges as determined above are subject to a fuel cost adjustment as provided for in Section 9. of the Preliminary Statement. The fuel cost adjustment billing factor set forth therein will be applied to all kilowatt-hours billed under this schedule.

Franchise Fee Differential

A franchise fee differential as indicated below will be applied to the monthly billings calculated under this schedule for all customers within the corporate limits as follows:

City of San Diego 1.9%

Such franchise fee differential shall be so indicated and added as a separate item to bills rendered to such customers.

SCHEDULE A-5 (continued)

SPECIAL CONDITIONS

1. Revise Special Condition 1 as follows:

   1. Voltage. This schedule is applicable where the customer receives service at a standard voltage of the utility above 2 kv.

2. Revise Special Condition 4 as follows:

   4. Billing Demand. The billing demand will be based on kilowatts of maximum demand as measured each month, provided that the billing demand shall in no case be less than the highest of (a) 100 kw, (b) 80 percent of the highest billing demand registered during the preceding eleven months.

   For maximum demands occurring between the hours of 10 p.m. to 7 a.m. of the following day, only 60 percent of such maximum demand shall be considered.

3. Revise Special Condition 7 and 8 into Special Condition 7 as follows:

   7. Miscellaneous. This schedule is not applicable to standby, auxiliary service, or service operated in parallel with a customer's generating plant. Submetering or resale of energy will not be permitted.

SCHEDULE A-6

RATES

Energy Charge:

	Per Meter Per Month
First 100 kwhr per kw of billing demand per kwhr	3.127¢
Next 100 kwhr per kw of billing demand, per kwhr	2.577
Next 100 kwhr per kw of billing demand, per kwhr	2.077
All excess kwhr, per kwhr	1.787

Minimum Charge

The monthly minimum charge shall be $5,917.00 but not less than $1.18 per kw of billing demand.

Fuel Cost Adjustment

The charges as determined above are subject to a fuel cost adjustment as provided for in Section 9. of the Preliminary Statement. The fuel cost adjustment billing factor set forth therein will be applied to all kilowatt-hours billed under this schedule.

Franchise Fee Differential

A franchise fee differential as indicated below will be applied to the monthly billings calculated under this schedule for all customers within the corporate limits as follows:

City of San Diego 1.9%

Such franchise fee differential shall be so indicated and added as a separate item to bills rendered to such customers.

SPECIAL CONDITIONS

1. Revise Special Condition 4 as follows:

4. Billing Demand. The billing demand will be based on kilowatts of maximum demand as measured each month, provided that the billing demand shall in no case be less than the highest of (a) 5,000 kw, (b) 80 percent of the highest maximum demand registered during the preceding eleven months, or (c) the diversified resistance welder load computed in accordance with the utility's Rule 2F-2b.

For maximum demands occurring between the hours of 10 p.m. to 7 a.m. of the following day only 60 percent of such maximum demand shall be considered.

SCHEDULE A-6 (Continued)

SPECIAL CONDITIONS (Continued)

2. Revise Special Condition 6 to increase the charge per kilovar from 14¢ to 15¢.

3. Delete Special Conditions Nos. 7, 8, 9, 10 and 11 and add the following:

   7. Limitation on Multi-family Service. This schedule is not applicable to service to multi-family housing projects or other services associated therewith, except housing on the premises of educational institutions, industrial plants and military establishments when such housing is associated with the operation of the establishment.

   8. Contract. A contract for an initial period of ten years, and for subsequent periods of five years each thereafter, will be required for each customer served under this schedule. This contract may be canceled at the end of the initial period or at the end of any subsequent period, provided written notice is given two years in advance of the end of any such period.

   9. Customer's Right to Terminate. In the event the net bill for electric service to the customer is increased as a result of changes in this schedule, the customer shall have the right to terminate the contract upon written notice given one year in advance of the date such service is to terminate, and given within 90 days after the effective date of such change.

   10. Standby Service. This schedule is not applicable to standby, auxiliary service or service operated in parallel with a customer's generating plant. Submetering or resale of energy will not be permitted.

APPENDIX C

SCHEDULES D-1, D-2, D-3, & D-4

RATES

	Per Meter Per Month Schedule No. D-1	D-2	D-3	D-4
Customer Charge	$ .86	$1.02	$1.18	$1.35
Energy Charge (to be added to Customer Charge):				
First 40 kwhr, per kwhr	5.518¢	5.748¢	6.158¢	6.658¢
Next 60 kwhr, per kwhr	4.128¢	4.248¢	4.448¢	4.658¢
Next 100 kwhr, per kwhr	3.878¢	3.878¢	3.878¢	3.878¢
All excess kwhr, per kwhr.	2.758¢	2.758¢	2.758¢	2.758¢

Minimum Charge

The minimum monthly charge shall be the customer charge.

Fuel Cost Adjustment

The charges as determined above are subject to a fuel cost adjustment as provided for in Section 9 of the Preliminary Statement. The fuel cost adjustment billing factor set forth therein will be applied to all kilowatt-hours billed under this schedule.

Franchise Fee Differential

A franchise fee differential as indicated below will be applied to the monthly billings calculated under this schedule for all customers within the corporate limits as follows:

City of San Diego 1.9%

Such franchise fee differential shall be so indicated and added as a separate item to bills rendered to such customers.

SCHEDULE H

RATES

Energy Charge:	Per Meter Per Month
First 100 kwhr or less	$6.00
Next 400 kwhr, per kwhr	5.089¢
Next 500 kwhr, per kwhr	3.809¢
All excess kwhr, per kwhr	3.189¢

Minimum Charge:

Per kw of connected heating load	$0.69
Per hp of connected other power load	$1.38
The total minimum charge shall not be less than..	$6.00

Fuel Cost Adjustment

The charges as determined above are subject to a fuel cost adjustment as provided for in Section 9. of the Preliminary Statement. The fuel cost adjustment billing factor set forth therein will be applied to all kilowatt-hours billed under this schedule.

Franchise Fee Differential

A franchise fee differential as indicated below will be applied to the monthly billings calculated under this schedule for all customers within the corporate limits as follows:

City of San Diego 1.9%

Such franchise fee differential shall be so indicated and added as a separate item to bills rendered to such customers.

SCHEDULE LS-1

RATES

Incandescent Lamps	Per Lamp Per Month
2,500 lumens	$4.21
4,000 lumens	5.40
6,000 lumens	6.74
10,000 lumens	9.47

Mercury Vapor Lamps

Lamp Watts	Approximate Lumens	Clear	Phosphor-Coated
175	7,000	$ 5.52	$ 5.59
250	10,000	6.74	6.79
400	20,000	8.56	8.62
700	35,000	13.66	13.78
1,000	55,000	17.22	17.33

Fuel Cost Adjustment

The charges as determined above are subject to an adjustment amount as provided for in Section 9. of the Preliminary Statement.

Franchise Fee Differential

A franchise fee differential as indicated below will be applied to the monthly billings calculated under this schedule for all customers within the corporate limits as follows:

City of San Diego 1.9%

Such franchise fee differential shall be so indicated and added as a separate item to bills rendered to such customers.

SPECIAL CONDITIONS

1. Revise Special Condition 4 to increase the charge for center suspension lamps from $2.43 to $2.61 per lamp per month and for lamps on wood pole in non-standard position from $1.22 to $1.31 per lamp per month.

2. Revise Special Condition 8 to increase the adjustments offered for the 175-watt lamp size reactor ballast from 20¢ to 23¢ per lamp per month and for the 250-watt lamp size reactor ballast from 25¢ to 28¢ per lamp per month.

SCHEDULE LS-2

RATES

(A) Charge for Energy Only:

	Per Lamp Per Month All Night: Standard or Regular Lamps	Per Lamp Per Month All Night: Group Replacement Lamps
Incandescent Lamps		
1,000 lumens	$ 0.77	$0.84
2,500 lumens	1.96	2.10
4,000 lumens	3.02	3.16
6,000 lumens	4.17	4.37
10,000 lumens	6.46	6.79
Mercury Vapor Lamps		
175 watts (7,000 lumens)	2.53	-
250 watts (10,000 lumens)	3.55	-
400 watts (20,000 lumens)	5.36	-
700 watts (35,000 lumens)	9.05	-
1,000 watts (55,000 lumens)	12.89	-

	Per Lamp Per Month			
	Midnight		1:00 A.M.	
Incandescent Lamps	Standard or Regular Lamps	Group Replacement Lamps	Standard or Regular Lamps	Group Replacement Lamps
1,000 lumens . . .	$0.59	$0.66	$0.62	$0.70
2,500 lumens . . .	1.44	1.51	1.55	1.63
4,000 lumens . . .	2.12	2.20	2.30	2.39
6,000 lumens . . .	2.95	3.09	3.19	3.34
10,000 lumens . . .	4.72	4.84	5.06	5.24

SCHEDULE LS-2 (continued)

RATES (continued)

(b) Charge for Energy and Limited Maintenance (optional and subject to special conditions):

Incandescent Lamps	All Night	Per Lamp Per Month Midnight	1:00 A.M.
2,500 lumens	$2.79	$1.91	$2.09
4,000 lumens	3.78	2.60	2.84
6,000 lumens	5.26	3.63	3.95
10,000 lumens	7.88	5.40	5.76

Mercury Vapor Lamps	Clear	Phosphor-Coated		
175 watts (7,000 lumens)	$3.97	$3.99	-	-
250 watts (10,000 lumens)	4.95	4.99	-	-
400 watts (20,000 lumens)	6.92	6.98	-	-
700 watts (35,000 lumens)	11.10	11.19	-	-
1,000 watts (55,000 lumens)	15.20	15.30	-	-

Fuel Cost Adjustment

The charges as determined above are subject to an adjustment amount as provided for in Section 9. of the Preliminary Statement.

Franchise Fee Differential

A franchise fee differential as indicated below will be applied to the monthly billings calculated under this schedule for all customers within the corporate limits as follows:

City of San Diego 1.9%

Such franchise fee differential shall be so indicated and added as a separate item to bills rendered to such customers.

SPECIAL CONDITIONS

1. Revise the second paragraph of Special Condition 5 as follows:

   In the case of all night installations not controlled by an established series circuit, the customer will install and maintain a standard or astronomical time switch, or switch controlled by a photoelectric cell, either of which, under normal conditions, will result in approximately 4,033 burning hours per year during the hours of darkness.

SCHEDULE LS-3

RATES

	Per Meter Per Month
First 150 kwhr per kw of billing demand, per kwhr. .	4.655¢
All excess kwhr, per kwhr.	2.455¢

Minimum Charge

For each point of delivery the monthly minimum charge shall be $6.25.

Fuel Cost Adjustment

The charges as determined above are subject to a fuel cost adjustment as provided for in Section 9, of the Preliminary Statement. The fuel cost adjustment billing factor set forth therein will be applied to all kilowatt-hours billed under this schedule.

Franchise Fee Differential

A franchise fee differential as indicated below will be applied to the monthly billings calculated under this schedule for all customers within the corporate limits as follows:

City of San Diego 1.9%

Such franchise fee differential shall be so indicated and added as a separate item to bills rendered to such customers.

SCHEDULE LS-4

Monthly Rates

	Lamp Watts	One Luminaire per Electrolier	Two Luminaires per Electrolier
Rate A			
Mercury Vapor Lamps	175	$ 8.73	$12.01
	250	11.10	15.18
	400	12.98	18.36
	700	19.75	29.16
	1,000	23.05	34.77
High Pressure Sodium Vapor Lamps	250	$15.46	$23.91
	400	18.45	27.75

Rate B

The Rate A charge plus $0.0172 per month for each dollar of investment by the utility in excess of the investment in the standard installation.

Fuel Cost Adjustment

The charges as determined above are subject to an adjustment amount as provided for in Section 9. of the Preliminary Statement.

Franchise Fee Differential

A franchise fee differential as indicated below will be applied to the monthly billings calculated under this schedule for all customers within the corporate limits as follows:

City of San Diego 1.9%

Such franchise fee differential shall be so indicated and added as a separate item to bills rendered to such customers.

SCHEDULE OL-1

RATES

Lamp - (Installation on existing support)	Per Lamp Per Month
175-watt mercury-vapor lamp	$5.71
400-watt mercury-vapor lamp	8.88

Pole - (New utility-owned wood pole installation)	Per Pole Per Month
30 foot wood pole	$2.70
35 foot wood pole	3.10

Fuel Cost Adjustment

The charges as determined above are subject to an adjustment amount as provided for in Section 9. of the Preliminary Statement.

Franchise Fee Differential

A franchise fee differential as indicated below will be applied to the monthly billings calculated under this schedule for all customers within the corporate limits as follows:

City of San Diego 1.9%

Such franchise fee differential shall be so indicated and added as a separate item to bills rendered to such customers.

SCHEDULE OL-ME

RATES

Lamp - (Installation on existing support)	Per Lamp Per Month
7,000 Lumens (175-watt) Mercury-vapor lamp	$5.41
20,000 Lumens (400-watt) Mercury-vapor lamp	8.58

Poles - (New utility-owned wood pole installation)	Per Pole Per Month
30 foot wood pole	$1.13

Fuel Cost Adjustment

The charges as determined above are subject to an adjustment amount as provided for in Section 9. of the Preliminary Statement.

SCHEDULE DWL

RATES

	Per Month
Facilities Charge:	
Per dollar of utility investment in walkway lighting facilities	$ .016
Energy and Lamp Maintenance Charge (to be added to the Facilities Charge):	
100 watt mercury-vapor lamp, per lamp	1.50
Minimum Charge:	
Per Customer	79.61

Fuel Cost Adjustment

The charges as determined above are subject to an adjustment amount as provided for in Section 9 of the Preliminary Statement.

Franchise Fee Differential

A franchise fee differential as indicated below will be applied to the monthly billings calculated under this schedule for all customers within the corporate limits as follows:

City of San Diego 1.9%

Such franchise fee differential shall be so indicated and added as a separate item to bills rendered to such customers.

SCHEDULE P

RATES

Horsepower of Connected Load or Billing Demand*	SERVICE CHARGE $ per hp per mo.	ENERGY CHARGE TO BE ADDED TO SERVICE CHARGE First 100 kwhr per hp per mo., per kwhr	Next 100 kwhr per hp per mo., per kwhr	All excess kwhr, per kwhr
2 to 4.9	$1.08	4.307¢	2.963¢	2.425¢
5 to 14.9	.95	4.049¢	2.834¢	2.306¢
15 to 49.9	.73	3.770¢	2.705¢	2.167¢
50 to 99.9	.73	3.372¢	2.565¢	2.167¢
100 to 249.9	.68	3.103¢	2.425¢	2.167¢
250 to 499.9	.68	2.834¢	2.425¢	2.167¢
500 & Over	.68	2.705¢	2.306¢	2.167¢

* See Special Condition 8.

Minimum Charge

The monthly minimum charge shall be the service charge, except that:

1. The minimum charge shall not be less than $6.788 per month for three-phase service, or

2. The minimum charge shall not be less than $67.78 per month where charges are based on maximum demand as provided in Special Condition 8.

Fuel Cost Adjustment

The charges as determined above are subject to a fuel cost adjustment as provided for in Section 9 of the Preliminary Statement. The fuel cost adjustment billing factor set forth therein will be applied to all kilowatt-hours billed under this schedule.

Franchise Fee Differential

A franchise fee differential as indicated below will be applied to the monthly billings calculated under this schedule for all customers within the corporate limits as follows:

City of San Diego 1.9%

SCHEDULE P-ME

RATES

Demand Charge

	Per Meter Per Month
First 50 kw of billing demand, per kw	$2.18
All excess kw of billing demand, per kw	1.87

Energy Charge (to be added to Demand Charge)

First 100 kwhr per kw of billing demand, per kwhr . .	3.737¢
Next 100 kwhr per kw of billing demand, per kwhr . .	3.113
All excess kwhr, per kwhr	2.737

Minimum Charge

The proposed monthly minimum charge is $0.94 per kva of required transformer capacity but in no case less than $31.20 per month.

Fuel Cost Adjustment

The charges as determined above are subject to a fuel cost adjustment as provided for in Section 9. of the Preliminary Statement. The fuel cost adjustment billing factor set forth therein will be applied to all kilowatt-hours billed under this schedule.

SPECIAL CONDITIONS

1. Revise Special Condition 1. as follows:

   1. Annual Minimum Charge. Customers requiring service during certain seasons not exceeding nine (9) months per year may guarantee a minimum annual charge, in which case there shall be no monthly minimum charge. Such annual minimum charge shall be $11.30 per kva of required transformer capacity, but not less than $374.38.

SCHEDULE PA

RATES

Horsepower of Connected Load	Per Meter ANNUAL SERVICE CHARGE $ per hp per year	Per Meter Per Month ENERGY CHARGE In Addition to Annual Service Charge: First 1,000 kwhr per hp per year, per kwhr	Next 1,000 kwhr per hp per year, per kwhr	All excess kwhr, per kwhr
2 to 4.9	8.68	3.823¢	2.748¢	2.350¢
5 to 14.9	8.01	3.544¢	2.618¢	2.350¢
15 to 49.9	7.75	3.146¢	2.618¢	2.350¢
50 to 99.9	7.48	3.016¢	2.479¢	2.350¢
100 to 249.9	7.21	2.887¢	2.350¢	2.081¢
250 to 499.9	6.94	2.748¢	2.350¢	2.081¢
500 & Over	6.68	2.618¢	2.210¢	2.081¢

Annual Service Charge

The annual service charge is payable in six equal monthly installments as provided in Special Condition 7.

Minimum Charge

The proposed minimum charge shall be the annual service charge, but not less than $26.03 for three-phase service.

Fuel Cost Adjustment

The charges as determined above are subject to a fuel cost adjustment as provided for in Section 9 of the Preliminary Statement. The fuel cost adjustment billing factor set forth therein will be applied to all kilowatt-hours billed under this schedule.

SCHEDULE PDC

RATES

Energy Charge:	Per Meter Per Month
First 100 kwhr, per kwhr	10.665¢
Next 400 kwhr, per kwhr	9.299¢
Next 500 kwhr, per kwhr	6.567¢
All excess kwhr, per kwhr	5.200¢

Minimum Charge

The monthly minimum charge shall be $1.39 per horsepower per month.

Fuel Cost Adjustment

The charges as determined above are subject to a fuel cost adjustment as provided for in Section 9. of the Preliminary Statement. The fuel cost adjustment billing factor set forth therein will be applied to all kilowatt-hours billed under this schedule.

Franchise Fee Differential

A franchise fee differential of 1.9% will be applied to the monthly billings calculated under this schedule for all customers within the corporate limits of the City of San Diego. Such franchise fee differential shall be so indicated and added as a separate item to bills rendered to such customers.

SCHEDULE S

RATES

Standby Charge:	Per Meter Per Month
First 20 kw or less of contracted demand	$68.58
All excess kw of contracted demand, per kw	2.74

Regular Schedule Charges (to be added to Standby Charge):

The charges as determined under regularly filed schedules applicable to the service rendered.

Minimum Charge

The monthly minimum charge shall be the standby charge.

Franchise Fee Differential

A franchise fee differential as indicated below will be applied to the monthly billings calculated under this schedule for all customers within the corporate limits as follows:

City of San Diego 1.9%

Such franchise fee differential shall be so indicated and added as a separate item to bills rendered to such customers.

SCHEDULE SE

RATE

For each establishment, supersedure, or re-establishment of electric service $1.18

SPECIAL CONDITIONS

1. Revise Special Condition 2 to increase the addition charge from $3.40 to $3.66.

SCHEDULE E - Withdraw Schedule E

SPECIAL CONTRACTS 103, 104, 105, 106, 107, 108, 109, 110, 113, 116, 118, 119, 130, 131, 138, 139, 140, 145, 147, 154, 162 AND 188

Increase the annual additional charge percentage for use of alternate service facilities from 18% to 19.4%.

SPECIAL CONTRACTS 124, 125, 126, 135, 141, 142, 143, 144, 156, 177, 180, AND 201

Increase the annual additional charge percentage for use of special facilities from 18% to 19.4%.

SPECIAL CONTRACT 171

Increase the additional monthly charge for each lamp from $0.24 to $0.26.

SPECIAL CONTRACT 175

Increase the monthly charge from $234.71 to $369.30.

Rule 2

Revise Section I.1.b.(1), Special Facilities, of Rule 2 to increase the monthly facility charge percentage for use of special facilities from 1.50% to 1.62%.

Rule 20

Delete the free-footage allowance stated in Section B.1.b. of Rule 20 for street lighting requiring pole line extensions.

PRELIMINARY STATEMENT

1. Revise Section 9.(d), Fuel Cost Adjustment Billing Factor, of the Preliminary Statement by deleting "62.56 cents per million Btu" from the first sentence and inserting "159.72 cents per million Btu."

2. Revise Section 9.(h), Fuel Cost Adjustment Billing Factor of the Preliminary Statement by deleting the date "October 5, 1974" and inserting the effective date of the rates authorized by this decision, by deleting "0.988 cent per kilowatt-hour" and inserting "0.000 cent per kilowatt-hour", and by deleting the adjustment amounts to be added per month for all the lamp ratings and Special Contract 175.

APPENDIX D

RATES - SAN DIEGO GAS & ELECTRIC COMPANY
Steam Department

Applicant's rates, charges and conditions are changed to the level or extent set forth in this appendix.

Rates authorized include Fuel Clause Adjustments through October 5, 1974.

GENERAL STEAM SERVICE

RATES

	Per Meter Per Month Base Rates
Customer Charge	$6.50
Commodity Charge - Monthly Consumption in Pounds:	
First 100,000 lb., per 1,000 lb.	2.69
Next 100,000 lb., per 1,000 lb.	2.56
Next 100,000 lb., per 1,000 lb.	2.43
All excess, per 1,000 lb.	2.26

A. 53945 et al.

APPENDIX E

BASE COST OF FOSSIL FUEL

REFLECTED IN AUTHORIZED RATES

A. 53945 et al.

San Diego Gas & Electric Company
Electric Department

FOSSIL FUEL COST ESTIMATE

12 Months Ended September 30, 1975

Item	Net System Input M^2 Kwhr	Heat Equivalent M^3 Btu	Unit Cost ¢/M^2 Btu	Fossil Fuel Cost M$	Net Heat Rate Btu/Kwhr	Generation % Energy	Generation % Co. Gen.	Heat Equivalent % Fuel	Heat Equivalent % Fossil Fuel
Energy Sources									
Purchased Power	825.31					8.59			
Fuel									
Nuclear	593.28	6,096.5			10,276	6.18	6.76	6.35	
Coal									
Gas and Oil Units									
Natural Gas		25,167.3	69.287	17,438				26.22	28.00
Sludge Gas									
Diesel Oil		2,925.0	224.56	6,568				3.05	3.25
Residual Oil		61,789.8	193.49	119,557				64.38	68.75
Subtotal Gas and Oil	8,185.99	89,882.1	159.72	143,563	10,980	85.23	93.24		
Total Energy	9,604.58					100.00			
Company Generated	8,779.27	95,978.6					100.00		
Fuel	8,779.27	95,978.6						100.00	
Fossil Fuel	8,185.99	89,882.1		143,563					100.00

APPENDIX E