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Decision No. 92549 December 30, 1980

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of SOUTHERN CALIFORNIA EDISON COMPANY for authority to increase rates charged by it for electric service.	Application No. 59351 (Filed December 26, 1979)

(Appearances are listed in Appendix A.)

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O P I N I O N

I. SUMMARY OF THIS DECISION

Based upon the estimated results of operations for Southern California Edison Company (Edison) for the test year 1981, this decision finds that the utility should be allowed a return on equity of 14.95 percent and that a related average rate of return of 11.20 percent on rate base will be just and reasonable for the two-year period 1981-1982. In order to earn this rate of return on the adopted test year rate base for California jurisdictional operations, Edison is granted a stepped increase in gross revenues of $294.2 million effective January 1, 1981 and, to offset attrition in earnings, a further increase of $91.9 million effective January 1, 1982. The utility will refund to its customers any rate base revenues for 1981 exceeding the base rate revenues adopted in this decision.

The impact on the consumer of this increase in Edison's base rates is offset by a concurrent reduction in Edison's energy cost billing factors in the amount of $193.8 million. The Commission ordered this reduction by Decision No. 92550, dated December 30, 1980.

Under the adopted electric rate design, the residential lifeline base rate, which has been in effect since January 1, 1976, will now be increased on January 1, 1981 by approximately 6.6 percent. The resulting total average residential lifeline rate of 5.459¢/kWh, including the Energy Cost Adjustment Clause (ECAC) adjustment of 2.190¢/kWh, is 18.2 percent below the total average system rate.

At the same time, the residential base rate for quantities above lifeline will be increased by 41 percent, absorbing a significant portion of the increase which would otherwise fall upon lifeline usage. The increase in the difference between the residential lifeline rate and the nonlifeline tailblock rate should provide a meaningful economic signal to residential customers and should encourage curtailment of consumption above the lifeline allowance.

This decision reaffirms the Commission's emphasis upon the critical need for improved energy efficiency. Conservation is a valuable energy resource which Edison and California's other energy utilities must aggressively develop. The decision commits Edison to increased developmental and fuel cost-efficient implementation of conservation opportunities. We expect Edison to invest a dollar in conservation whenever that dollar offers ratepayers the potential for conserved energy equal to or less costly than alternative energy sources.

For the test year 1981 Edison has been authorized a total expenditure of $39,000,000 for load management and energy conservation programs. In so doing, the Commission has put Edison on notice that it is not thoroughly satisfied with its conservation progress to date. Wide avenues of cost-effective conservation approaches are open to Edison, and a number of them have been identified within the additional conservation requirements we are laying on Edison in this decision.

The rate relief granted by this decision conforms to Federal Wage and Price Guidelines.

II. INTRODUCTION

A. EDISON'S REQUEST

On October 26, 1979 the Commission accepted from Edison NOI 9[1/], a Notice of Intent (NOI) to file a general rate increase application for authority to increase its base rates[2/] for electric service to yield $292,000,000 in additional revenues for the test year 1981.

When Edison filed this application on December 26, 1979, it raised the amount of additional revenues requested to $340,000,000 for the test year. The rates proposed in the application would increase gross revenues by 9.0 percent based upon Edison's forecast of the level of sales for 1981.

Table II-A shows Edison's test year 1981 estimates of annual revenue increase, the average percentage increase, and the increase in unit revenues which would result from the requested increase for each of the affected customer groups.

1/ The NOI was filed in accordance with the Regulatory Lag Plan for Major Utility General Rate Cases as prescribed by Resolution No. A-5693 adopted by the Commission on July 6, 1977.

2/ Base rates exclude all energy costs and most costs directly related to the procurement and handling of energy. Under Commission procedure, Edison is permitted to recover reasonably incurred energy costs through the mechanism of an ECAC in its filed tariffs. The reasonableness of Edison's fuel and purchased power costs, as reflected in the rates actually charged the electricity user, are subjected to full analysis and testing in separate ECAC rate applications which are filed with this Commission from time to time.

TABLE II-A

PROPOSED INCREASE BY CUSTOMER GROUP
TEST YEAR 1981

Customer Group	Annual Revenue Increase $M	Average Percentage Increase %	Average Unit Revenue Increase ¢/kWh
Domestic	$153,303	13.3%	0.89¢/kWh
Lighting and Small Power	89,962	10.4	0.76
Large Power	28,749	9.6	0.61
Time of Use	43,923	3.5	0.21
Agricultural and Pumping	14,582	11.6	0.80
Streetlighting	9,664	17.2	1.78
	$340,183	9.0%	0.60¢/kWh

The impact of Edison's proposed rate design on typical monthly domestic service electric bills is shown in Table II-B.

TABLE II-B

IMPACT OF EDISON'S PROPOSAL ON TYPICAL DOMESTIC BILL

kWh	Present	Proposed	Increase***
500*	$35.17	$39.69	12.85%
1,000**	66.02	75.31	14.07

* Average domestic consumption that includes a basic lifeline quantity of 240 kWh.

** Reflects use of an electric water heater and includes an additional water heater lifeline allowance of 250 kWh.

*** Reflects increase in monthly customer charge from the present $2 to the proposed $3.75.

In the application Edison estimates that the requested rates would, if in effect for the full year 1981, yield on California jurisdictional operations a rate of return of 11.18 percent, which would decline to 10.38 percent for the year 1982. Thus, over the two-year minimum interval between general rate applications contemplated by the Commission's Regulatory Lag Plan, an average rate of return of 10.78 percent would be realized, barring extraordinary changes in Edison's operations, such as bringing on line a new major generating unit.

Such a new major unit, San Onofre Nuclear Generating Station Unit No. 2 (SONGS 2), is scheduled for commercial operation July 1, 1981, the middle of the test year. Edison has, however, excluded from the test year 1981 data included in this request all costs and revenue requirements associated with SONGS 2. Edison has made this exclusion so that separate treatment can be given to the revenue requirement associated with that new generating plant by another application to be filed subsequently for that specific purpose. Concurrent with the increase in revenue requirement resulting from the additional plant and expenses associated with SONGS 2 will be a reduction in its ECAC revenue requirement resulting from the lower-than-system-average fuel costs which will be incurred with that generating unit. Edison states that the subsequent application will request approval of a plan which would permit the increase in revenue requirement to be offset by the reduction in the ECAC rate to minimize the impact of SONGS 2 on billings to customers. To achieve this objective, Edison states that it will propose a balancing account procedure in the application.

The present level of Edison's base rates was authorized by Decision No. 89711 dated December 12, 1978 in Application No. 57602. The Commission found an overall rate of return of 9.6 percent, including a 13.49 percent return on equity to be reasonable based on the adopted results of Edison's jurisdictional operations for the test year 1979 used in that decision. In the present application Edison states that the base rates authorized by Decision No. 89711 have not produced a 9.6 percent rate of return because the authorized increase in rates was based on estimates of expenses and rate base which proved to be significantly lower than the actual level of expenses and rate base for the year 1979 even though revenues were somewhat higher than those adopted for fixing rates. Edison contends that continued inflation without rate relief will result in even greater earning deficiencies in 1980 and 1981.

The evidence presented by Edison in Application No. 57602 indicated an annual erosion of about 0.4 to 0.5 percent in return on rate base at the then current rate of inflation. Edison points out that the rate of inflation has increased since evidence based on a 1979 test year was prepared for that rate case. Edison states that, considered with the retardant effect on sales of increased conservation and load management efforts mandated by the Commission and notwithstanding the approval by the Commission of the new ECAC provision in its retail tariffs, the earnings erosion during 1981-1982 will be about 0.8 percent per year. This erosion will result from factors other than fuel and purchased power cost increases, excluding the impact on earnings of adding SONGS 2 planned for operation in mid-1981.

According to Edison, increases in embedded senior capital costs, because of higher interest and dividend rates for new issues, will increase its composite cost of capital even without an increase in the allowed return on common equity; hence, an increase in allowed rate of return is necessary. Edison states that its financial position is unlike that of the electric utility industry, generally, which has regained sufficient stature with the investment community to enable new common equity issues to be marketed near book value. Edison contends that this state of affairs indicates that continued investor disfavor is being engendered by (1) the Commission's inadequate allowance of return on rate base and (2) Edison's persistent inability to realize that inadequate level of return.

The following is a breakdown of the elements included in the application in justification of Edison's request for an increase in base rates of $340.2 million:

1. $18.9 million due to the deficiency in test year 1979 estimates adopted in the last general rate increase by Decision No. 89711.
2. $226.4 million due to attrition in rate of return from estimated test year 1979 through estimated test year 1981.
3. $56.9 million due to the increased cost of capital and the utility's proposal to increase the return on equity from 13.49 percent to 15.0 percent.
4. $38.0 million due to attrition in earnings beyond the test year 1981.

B. EDISON'S ELECTRIC DEPARTMENT OPERATIONS

Edison sells electricity as a public utility in a 50,000-square mile service area within 15 counties in central and southern California. The estimated population of this service area exceeds 8,000,000. Retail electrical service is furnished within 800 cities and communities through the facilities of its interconnected and integrated utility system. Edison also sells electricity for resale to the cities of Anaheim, Azusa, Banning, Colton, Riverside, and Vernon. Electric power is sold to, purchased from, or interchanged with certain nonassociated utilities, municipalities, cooperatives, and public authorities, including the State of California, the U.S. Department of Interior, and the Bonneville Power Administration.

Edison owns and operates 36 hydroelectric plants, 12 thermal-electric generating plants, and one diesel electric plant. It operates one coal-fueled thermal-electric plant, owned jointly with others, one 80 percent-owned thermal-electric nuclear plant, and an electric distribution system owned by the city of Vernon. It owns jointly with others, who operate them, one coal-fueled thermal-electric plant and one gas-and-oil-fueled generating plant, which have a combined effective operating capacity under optimum conditions of about 14.3 million kW. These plants, together with transmission and distribution systems and a related communications system, are all located in central and southern California and Nevada with the exception of the generating unit Edison owns jointly with others at Yuma, Arizona, and the jointly owned coal-fueled electric generating plant at Four Corners in New Mexico. In addition, Edison has available to it about 1.24 million kW of firm capacity under terms of power purchase agreements and 331,000 kW of effective operating capacity at the Hoover Dam power plant.

Consumption of electricity by Edison's 3.1 million customers totaled 59.5 billion kWh in 1979, an increase of 4.4 percent compared to 1978. This was primarily a result of adding almost 100,000 new customers to the system which made 1979 the second highest year of customer growth in Edison's history.

C. PROCEDURAL SUMMARY

Pursuant to the Regulatory Lag Plan, two prehearing conferences were held in Los Angeles on January 3 and March 14, 1980 before the assigned Administrative Law Judge James F. Haley. A series of seven days of public hearings was held in February, March, and April 1980 in Visalia, Long Beach, Santa Ana, Los Angeles, Palm Springs, San Bernardino, and Santa Barbara, especially for the purpose of receiving testimony and statements directly from customers of Edison.

The public hearing in Visalia on February 14, 1980 was attended by more than 300 farmers who protested the amount of increase proposed by Edison for its PA-1 and PA-2 agricultural schedules. Farm customers, in smaller numbers, also appeared at the Santa Barbara, San Bernardino, and Palm Springs hearings to protest the proposed increases in the agricultural schedules.

Representatives of the California Community Colleges appeared at the Santa Ana hearing and expressed their concern with the impact of proposed time-of-use rates on their energy costs. At the Santa Barbara hearing representatives of the city of Oxnard and the city of Simi Valley urged acceleration of conversion of city streetlights from mercury-vapor to high-pressure sodium-vapor lamps.

Most of the other public witnesses appearing at this series of hearings recounted the difficulties of living on fixed or low incomes in the face of increasing utility bills. Several small business operators expressed concern with the impact of rising energy costs on their operations. Some of the public witnesses, however, supported the rate increase. For the most part these persons were

Edison shareholders who stated that they depended on utility dividends as part of their retirement income and that they needed greater dividends to offset the effects of inflation. There were a few complaints from customers who were dissatisfied with Edison's service or who believed that they were being overcharged. Edison was instructed by the Administrative Law Judge to review these problems and to submit reports thereon to the customers concerned and to the Commission. Edison has complied with these instructions.

Commencing April 1 and continuing through July 11, 1980, 44 additional days of hearing were held in Los Angeles on the substantive issues raised by the application. Testimony and exhibits were presented on all aspects of the application by Edison and the Commission staff. The California Energy Commission, the California Farm Bureau, the California Retailers Association, the California Manufacturers Association, and the California Industrial Energy Consumers participated through the presentation of witnesses and exhibits and the cross-examination of other witnesses on the subject of revenue allocation and rate design. The city of Long Beach presented evidence on streetlighting; a group of Christian Science Churches made a presentation respecting demand charges; the Western Mobilehome Association made a presentation regarding the rate schedules applicable to mobile home parks; Kimberly-Clark Corporation presented evidence on cogeneration; and California Association of Utility Stockholders presented an exhibit on the subject of rate of return.

The matter was taken under submission subject to the following: receipt of certain late-filed exhibits, which have been received; the filing of opening briefs on August 11, 1980; the filing of closing briefs on August 25, 1980; and oral argument before the Commission en banc, which was held on October 30, 1980.

At the oral argument, Edison asked the Commission, in reviewing the record as made, to focus on three major items which were based on assumptions made more than 18 months before, the dollar impacts of which cause the utility's revenue requirement to be drastically understated. In its argument Edison recited that these items are: (1) the decrease in forecasted sales and revenues, a $60 to $75 million item; (2) the increased costs related to existing wage settlement agreements, a $15 to $20 million item; and (3) increased costs related to cost of senior capital, a $9 million item. When taken together they indicate, according to Edison, a need for between $80 and $100 million of additional rate relief not contemplated by the application but which is supported by the record and should be adopted as the basis for this decision.

Upon consideration of the deteriorated earnings position of the utility in relation to the test year results in the record, the Commission set further hearings in this matter limited to: (1) the receipt of evidence on Edison's average cost of debt for test year 1981 and the corresponding effect on the proposed attrition allowance, and (2) the sales estimates for test year 1981. Beginning on

November 18, 1980, the Commission held three further days of hearing at which Edison and the staff offered their respective updated estimates of electricity sales and the cost of senior capital. On the last of these days, following cross-examination and oral argument, the matter was again taken under submission subject to the receipt of two late-filed exhibits, which the Commission has received.

III. RESULTS OF OPERATIONS

A. GENERAL

Edison and the Commission staff presented complete results of operations estimates to determine the revenue requirement of the utility based upon the test year 1981. The Edison and staff estimates, as finalized at the time of submission, together with adopted results of operations for the years 1981 and 1982 are summarized in Table III-A. The adopted results shown for California jurisdictional operations exclude ECAC revenues from operating revenues (i.e., reflect base rate revenues only) and exclude energy costs from operating expenses.

On April 15, 1980, after the staff and Edison had completed preparation of their results of operations reports for this proceeding, the Commission issued Decision No. 91561 in Applications Nos. 58329 and 58331 authorizing rate increases for Edison's Santa Catalina Island (Catalina) operation. In that decision we stated that we are inclined to continue to view the Catalina utility as a separate operation rather than integrating the island's electric operation with the mainland system for ratemaking purposes. Accordingly, we are reducing Edison's Electric Department revenue requirement in this proceeding by $2,130,000 to remove all of the effects of the Catalina operation from this decision. This is being done in two parts: (1) $1,212,000 to remove fuel costs related to the Catalina operation (see "Power Production Expenses [Fuel-Related]", infra); and (2) a further $918,000 reduction to remove all other Catalina effects from the adopted test year results of operations. (See Table III-A under the designation "Catalina Adjustment".)

B. OPERATING REVENUES

1. General

The base rate revenue estimates in this record were determined by forecasting for the test year the number of customers and the kWh of sales to those customers. Individual forecasts were made by Edison and the staff for each customer class. The staff's updated revenue estimate exceeds Edison's by $7,482,000[3] at present rates because the staff has forecasted 735,000,000 more kWh of sales than Edison. The 735,000,000 kWh difference results from the staff's forecasting of 3,000 more residential customers and 300 more

3/ Excluding increase in sales to the California Department of Water Resources.

commercial customers, as well as generally greater forecasts of usage per customer.

Updated estimates of test year 1981 operating revenues at present rates (after giving effect to Commission Resolutions E-1880, E-1881, E-1882, and E-1889[4]) are shown in Table III-Aa.

4/ Subsequent to Edison's initial presentation, the Commission adopted Resolutions E-1880, E-1881, E-1882, and E-1889 which have the effect of increasing Edison's net operating revenues by $165,000. This has no significant impact on the rate of return for the test year.

TABLE III-A

Southern California Edison Company
Electric Department
Results of Operations - Estimated Years 1981 and 1982

Item	Total Electric			CPUC Jurisdiction		
	Present Rates					
	Staff*	Utility	Adopted	Adopted	Authorized Rates-1981	Authorized Rates-1982
	($000 Omitted)					
Operating Revenues	1,538,750	1,521,996	1,480,002	1,224,642	1,518,838	1,610,765
Operating Expenses						
Production-FERC Fuel	195,609	195,609	195,609	-	-	-
Production-CPUC Juris. Fuel	17,590	18,010	18,010	18,010	18,010	18,010
Production-Other	167,829	181,435	173,609	160,857	160,857	160,857
Transmission	45,879	45,879	45,879	42,044	42,044	42,044
Distribution	101,230	101,230	101,730	101,621	101,621	101,621
Customer Accounts	46,106	47,806	47,487	47,443	47,443	47,443
Uncollectibles	3,319	3,454	2,809	2,809	3,494	3,708
Customer Service & Info.	39,000	39,000	39,000	39,000	39,000	39,000
Administrative & General	145,754	153,477	146,158	140,569	140,569	140,569
Franchise Req.	10,077	10,140	9,473	9,352	11,634	12,347
Subtotal	772,393	796,040	779,764	561,705	564,672	565,599
Wage Adjustment	-	15,927	21,753	21,064	21,064	21,064
Allowance for Oper. Attrition	-	-	-	-	-	91,000
Catalina Adjustment	-	-	(930)	(930)	(930)	(930)
Subtotal	772,393	811,967	800,587	581,839	584,806	676,733
Depreciation	202,107	204,506	203,423	193,993	193,993	193,993
Taxes Other Than Income	63,566	74,576	61,876	58,951	58,951	58,951
Income Taxes	92,802	69,735	35,190	30,270	178,986	178,986
Total Oper. Expen.	1,130,868	1,160,784	1,101,076	865,053	1,016,736	1,108,663
Net Oper. Revenues	407,882	361,212	378,926	359,589	502,102	502,102
Rate Base	4,737,625	4,807,579	4,715,713	4,483,022	4,483,022	4,483,022
Rate of Return	8.61%	7.51%	8.04%	8.02%	11.20%	11.20%

*Reflects staff figures adjusted for FERC Fuel.

(Red Figure)

TABLE III-Aa

OPERATING REVENUES, EXCLUDING ECAC, AT PRESENT RATES
TEST YEAR 1981
(Thousands of Dollars)

Item	Staff	Edison
Revenue: Six Customer Groups	$1,213,038.4	$1,205,579.4
Catalina	867.0	843.6
MWD Off-Peak	12.3	12.3
Fringe	140.0	140.0
Base Rate Revenues	1,214,057.7	1,206,575.3
FERC Revenue (Excl. FCA)	160,472.1	160,472.1
Subtotal	1,374,529.8	1,367,047.4
Other Operating Revenues	21,104.0	20,845.0
FCA Revenue (FERC Related)	92,847.0	92,847.0
Total Operating Revenues (Excl. ECAC)	$1,488,480.8	$1,480,739.4

2. Comparison of Estimates

a. Customer Estimates

Table III-B compares estimates for the test year 1981 for average customer months by customer groups.

TABLE III-B

AVERAGE CUSTOMER MONTHS BY CUSTOMER GROUP
TEST YEAR 1981

	Average Customer Months	
Customer Group	Staff	Edison
Domestic	2,851,285	2,848,285
Lighting & Power	316,105	315,805
Large Power	4,600	4,600
Time-of-Use	895	895
Agricultural Power	32,960	32,960
Streetlighting	8,215	8,215
Catalina	1,659	1,659
Metropolitan Wtr. Dist. (MWD)	1	1
Fringe	4	4
Resale (FERC)	12	12
Total	3,215,736	3,212,436

b. Sales Estimates

Table III-C shows a comparison of estimates of energy sales in kWh by customer groups for the test year 1981.

TABLE III-C

ENERGY SALES
TEST YEAR 1981

Customer Group	Sales in Millions of kWh Staff	Edison
Domestic	16,511.3	16,366.3
Lighting & Small Power	11,494.5	11,348.5
Large Power	7,937.9	7,738.9
Time-of-Use	16,161.1	15,936.1
Agricultural Power	1,901.6	1,881.6
Streetlighting	543.7	543.7
Catalina	15.3	14.9
MWD	0.0	0.0
Fringe	7.8	7.8
Resale (FERC)	4,691.2	4,691.2
Total Sales	59,264.4	58,529.0

c. Operating Revenue Estimates

Table III-D presents 1981 test year estimates by customer groups of operating revenue at present base rates.

TABLE III-D

OPERATING REVENUES BY CUSTOMER GROUP, EXCLUDING ECAC,
AT PRESENT RATES
TEST YEAR 1981

Customer Group	Revenues in Thousands of Dollars Staff	Edison
Domestic	$ 460,556.8	$ 456,971.4
Lighting & Small Power	310,947.1	309,554.7
Large Power	133,362.4	132,307.7
Time-of-Use	235,298.4	234,105.9
Agricultural Power	41,122.9	40,888.9
Streetlighting	31,750.8	31,750.8
Catalina	867.0	843.6
MWD	12.3	12.3
Fringe	140.0	140.0
Resale (FERC)	160,472.1	160,472.1
Total	$1,374,529.8	$1,367,047.4

3. Estimating Methodologies

Our review of the respective revenue estimates of Edison and the staff reveals a significant difference in their approaches to evaluating local economic impacts on residential, commercial, and industrial sales.

Edison developed a statewide econometric model as the basis for making its 1981 revenue estimates for all customer groups. Its estimates were then adjusted by judgment to reflect local economic conditions.

In its revenue determinations the staff, as did Edison, predicted a statewide economic downturn. Unlike Edison, however, the staff is of the opinion that local economic conditions will improve, rather than worsen. The staff witness testified that in his opinion the effects of the statewide downturn will be offset in Edison's territory by increased employment and greater per capita income generated by the aerospace industry and by the incoming Federal Administration's decision to increase defense spending, generally.

According to the staff witness, growth in aerospace may be expected to offset employment declines in other manufacturing sectors and, because of interactions within the economy, income generated by aerospace may also serve to protect other sectors of the Los Angeles economy from downturn. In support of his position that such growth does not track the general statewide economy, he cited the March 1980 UCLA Business Forecast for California (Exhibit 36), which projects aerospace employment growth during 1980 and 1981 at 3.4 times the general employment growth statewide. This equates to an employment growth of 8.6 percent in 1980 and 6.8 percent in 1981 for that sector. He pointed out that, although Exhibit 36 revises statewide personal income per capita downward from the October 1979 forecast, aerospace employment figures were revised upward from 619,000 to 675,000. We note that ten of the largest firms in the aerospace and defense industries are located within the Los Angeles area and that seven of them are served by Edison.

Both parties agree that the level of in-migration to the State as a whole will be on the order of 200,000 in 1981, but they disagree on the level of in-migration to the Edison service area from other states and other parts of California. The record shows that the level of in-migration to Edison's service area is extremely variable; however, there appears to be a distinct correlation between the level of such in-migration and the level of activity in the aerospace industry. Exhibit 36 shows a marked coincidence between increases and declines in aerospace employment and in-migration to the Edison service territory. The witness testified that he had determined that the Demographic Unit of the California Department of Finance considers that there is a relationship between population changes in the Los Angeles area and employment changes in the aerospace industry. According to his understanding, the Department attributes the near-zero net in-migration to Edison's service territory in 1972 to a loss of approximately 100,000 aerospace jobs during that year.

4. Revenue Refund

Although the staff updated its estimates of test year 1981 operating revenues at present rates, it noted the uncertainty regarding 1981 test year sales and revenues. As a result, staff proposed that the Commission adopt the company's estimated revenues subject to a refund methodology. Under this proposal, all base rate revenues for 1981 in excess of those estimated by the company would be refunded to ratepayers through a "one way" methodology. The method would set rates subject to refund and would apply to the six major categories of California jurisdictional sales (i.e., Domestic, Lighting and Small Power, Large Power, Time-of-Use, Agricultural Power, and Streetlighting). If the adopted revenues exceeded actual revenues for the above sales categories, the utility could not seek to recover any undercollection from ratepayers. Staff also proposed reevaluation of this methodology for the year 1982, when we implement the attrition allowance as discussed further herein, and possibly change the revenue refund level. The staff further recommended for 1982 that if Edison's recorded return on equity exceeds the one adopted by more than 50 basis points, the company would refund additional revenues to ratepayers.

Regarding revenues, Edison in its oral argument basically accepted the staff's refund proposal for 1981 with an increase in revenues for 1982 by an attrition allowance. Edison also proposed later hearings for quantifying the amount of the attrition allowance. Rate increases resulting from a rate base offset application for power plant additions would be considered as additions to the base level rates.

We have considered the staff's proposal and Edison's response. We agree that there is in this case difficulty in establishing proper sales and revenue estimates for the test year.

We believe that the staff's refund proposal is a reasonable approach to solving this difficult problem for the 1981 test year. Therefore, we will adopt Edison's estimate of base revenues and the concept of a "one way" refund of revenues, whereby Edison will be required to maintain a record of all jurisdictional base rate revenues authorized by this decision. At the beginning of 1982, Edison will be ordered to refund any base rate revenues exceeding the base rate revenues adopted herein. Revenues will be refunded to ratepayers as directed by this Commission. No interest will accrue to any credited revenues until January 1, 1982, when such an amount shall be considered.

With respect to other operating revenues, we shall adopt the staff's estimate because it is based upon more appropriate charges for pole space and anchors than were used in Edison's estimate.

We have also considered both the staff's and company's proposals on establishing rates for 1982, the attrition year. As discussed further herein, we are adopting the staff's proposal for step-rate attrition for 1982, which Edison supports. However, we cannot adopt the recommendation of any type of review process for any portion of results of operations. As we said in Decision No. 59316,

> "We simply do not have the staff to undertake such a potentially burdensome review in the middle of the rate life of a major energy utility general rate decision. The potential for establishing a 'mini-rate case' is all too obvious. We have developed the Regulatory Lag Plan to respond promptly to utility rate requests and to control the frequency with which such requests are filed, so that we can respond promptly. If we were to open the door to a mid-period filing for other than an extreme financial emergency, we would be undoing the carefully constructed Regulatory Lag Plan and the basis on which it operates. We would also severely strain existing staff resources which are already inadequate. We are unwilling to do this." (Mimeo, p. 70)

In addition, we are adopting a modification of the staff's recommendation that a limitation be set on the recorded 1982 return on equity. We will adopt a provision that if actual return on equity, on a ratemaking basis, exceeds the adopted, we will determine disposition of these excess revenues during the hearings for the 1983 test year consistent with the Regulatory Lag Plan. We believe that this provision will protect ratepayers from the possibility of any unreasonable return to the company.

The adoption of the refund provisions for revenues for 1981 and return on equity for 1982 are limited to Southern California Edison Company only because of the unique nature of Edison's decline in sales.

C. OPERATING EXPENSES

1. General

Both Edison in the application as filed and the staff in its presentation used a 7.0 percent wage escalation factor in determining estimated test year 1981 operating expenses. Subsequent to the filing of the application, Edison entered into a new wage contract which provides for increases greater than the 7.0 escalation factor used in preparing the test year estimates. All of the issues arising from the new wage agreement are treated in a separate section of this discussion on operating expenses under "Wage Settlement".

We have included no discussion of those groups of operating expenses concerning which no issues were raised in this proceeding. Such groups include Transmission Expenses and Distribution Expenses. The staff examined Edison's 1981 test year estimates for each of these groups of expenses and found them to be reasonable. We are including an additional $500,000 in distribution expenses to cover the cost of certain meters we are ordering Edison to install.

Customer Service and Informational Expenses are the group of operating expense accounts which include the utility's conservation and load management program. Edison proposes to fund this program with expenditures aggregating $39,000,000 during the test year 1981. The staff agrees that this is the appropriate level of funding; therefore, no issues have been raised as to the level of expenses in this group of accounts. The issues relating to the program itself are discussed in a separate portion of this opinion entitled "Conservation and Load Management".

2. Power Production Expenses (Excluding Fuel)

a. Steam Power Generation

(1) Operating, Supervision, and Engineering

The staff's estimate for Account 500 is $919,000 lower than Edison's. The difference has two components, $852,000 related to estimating methodology and $67,000 related to exclusion of the wages of certain employees.

As to estimating methodologies, the staff used a five-year average adjusted for inflation rather than a trended forecast as used by Edison. We are of the opinion that the nature of this account lends itself better to the staff's methodology, which we will discuss further herein.

As to the staff's proposed exclusion of the wages of certain employees from this account, it is apparent that this disallowance is the result of the staff's misunderstanding of the role of certain workers at the San Onofre generating station and that the exclusion is not appropriate.

We will adopt, as reasonable for the test year, the staff's estimate for Account 500, corrected to remove its proposed disallowance of $67,000 in wages.

(2) Generating Unit Overhauls

The staff's estimate for overhaul expenses includable in Accounts 506, 510, 511, 512, 513, and 514 is $3,920,000 lower than that of the utility. The staff witness on these expenses developed his estimates by reviewing budgeted amounts for past years for each of the generating units to be overhauled during the test year. He then converted budgeted amounts including an allowance for contingencies into 1981 dollars by using appropriate escalation factors. Edison relied largely on a subjective determination in developing its cost estimate, to the near exclusion of recorded experience.

We will adopt, as reasonable, the staff estimate for generating unit overhauls.

(3) Expenses Related to Off-System Energy Sales

The total difference in the estimates of the staff and Edison for maintenance expenses includable in Accounts 512 and 513 and related to economy energy sales is $5,143,000, the staff figure being the lower. This large difference results from adjustments made by the staff to the expenses recorded in these accounts to reflect revenues received by Edison from off-system sales in the years 1976, 1977, and 1978, mostly to Pacific Gas and Electric Company (PG&E) to assist in meeting severe energy shortages on that system resulting from low hydroelectric production associated with drought conditions.

Edison makes economy energy sales to utilities at incremental fuel costs with an additive of 0.2 mills per kWh for short-term maintenance expenses plus an overhead percentage to cover unquantifiable costs. Under Edison's ECAC procedures, the incremental fuel costs related to off-system sales are deducted from fuel costs related to main-system sales to the end that Edison's customers do not bear any of the costs associated with these sales.

In developing its test year estimates for Accounts 512 and 513, Edison adjusted recorded expenses for 1976, 1977, and 1978 by 0.2 mills per kWh to eliminate the effect of these sales on recorded maintenance expenses. The staff, on the other hand, adjusted expenses for the years in which the sales were made by excluding the entire difference between the fuel costs related to these sales and the revenues therefrom. This procedure reduced the trended expenses for the test year by $2,400,000 in Account 512 and $2,743,000 in Account 513.

The validity of the staff adjustments rests on the assumption that the difference between economy energy sales revenues and related fuel expense is a total measure of incremental expense in Accounts 512 and 513 for the year of sale. The record does not support this assumption. We will, therefore, not adopt the staff's adjustments to Accounts 512 and 513 for the expenses of economy energy sales.

While we are adopting the 0.2 mills per kWh cost factor as reasonable for purposes of this proceeding, we will, nevertheless, expect that Edison will be prepared to more fully justify its value in the next general rate proceeding.

(4) Air Preheater Elements

The staff has correctly determined that $702,000 should be deducted from Account 512 for the test year because Edison inadvertently included replacements in its estimates twice for replacement of air preheater elements at Alamitos Unit 4 and Redondo Beach Unit 5. However, the record shows that air preheater elements are deteriorating faster than Edison's original scheduling called for, and that $570,000 more in replacement costs than orginally estimated will be incurred during the test year for Redondo Beach Unit 7.

We will adopt for this expense item the utility's estimate reduced by $132,000, which is the difference between the $702,000 staff adjustment and the $570,000 increase in air preheater replacement costs anticipated for Redondo Beach Unit 7 in 1981.

b. Nuclear Power Generation

(1) Liquid Metal Fast Breeder Reactor (LMFBR)

The staff witness recommended a reduction of $1,055,000 to Account 524, Miscellaneous Nuclear Power Expense. He made this recommendation because Edison has made no payments on the LMFBR project during 1977, 1978, and 1979, and, further, because the Commission, in Decision No. 89711, supra, excluded this specific amount for ratemaking purposes.

Decision No. 89711 treated this issue as follows:

> "It appears that the President and Congress are working towards a consensus which would continue and/or modify current breeder reactor research programs, which would make more effective use of existing uranium weapons grade by-products. The governmental-industry research program is presently tied to the Clinch River LMFBR program. The status of this project is presently uncertain since Congress did not pass an authorization bill in 1978. Edison has a continuing interest in production of nuclear power at San Onofre and through its participation in the Palo Verde, Arizona, nuclear plants. The development of a reliable spent fuel reprocessing facility, together with a methodology for making more effective use of existing uranium resources, is a desirable goal. We will consider Edison's contribution to specific breeder R&D reactor in ratemaking. However, it does not appear that Edison will be called upon to make such a contribution in 1979 and we will therefore disallow this expense for test year 1979. However, if the expense is incurred, we will consider an amortization in Edison's next general rate case." (Mimeo p. 39.)

It does not appear that Edison will be called upon to make a payment to the LMFBR project during 1981, and Edison has modified its showing to exclude the $1,055,000 from the test year. Edison urges us, however, to include in this decision the same language respecting this question as contained in Decision No. 89711. Under the circumstances this is appropriate, and we hereby reaffirm that portion of Decision No. 89711 which relates to the LMFBR project. If Edison incurs expenses related to the LMFBR project, we shall consider their amortization in Edison's next general rate case.

(2) Estimating Methodology

In nuclear power generation expense Accounts 519, 520, 529, 530, 531, and 532, the staff estimates for the test year are lower than Edison's by a combined total of $2,896,000. In making its estimates for these accounts, Edison applied the trending methodology it generally used throughout its preparation of test year expense estimates, except where the data was completely random or where expenses were predictable without trending. Edison considered a historic period of data, separated the expenses into labor and other isolated unusual expense effects, and then adjusted for these amounts in the appropriate year, using a constant 1978 dollar basis. Edison then trended the data for the historic period by fitting a straight line to the points, using a least-squares curve-fitting technique. As a final step, Edison escalated costs to the 1981 level and then made any unusual adjustments judged necessary.

In making its estimates the staff used a somewhat similar approach. The staff reviewed each of the production expense accounts and prepared graphs for visual inspection. For accounts not showing apparent trends, the staff made regression analyses. For the above six accounts, however, the staff departed from this trending procedure because the results of the regression analysis studies were very poor. None of these accounts exhibited a trend, and the staff found that an average would be more appropriate for developing estimates for these accounts.

We are of the opinion that the staff-estimating methodology for these six accounts produces ratemaking projections more nearly representative of the test year 1981. We shall, therefore, adopt the staff's estimates for these accounts.

(3) Spent Nuclear Fuel Disposal

The staff recommends that Edison be required to file a report on the ratemaking aspects of disposing of its spent nuclear fuel. Chapter 19 of the staff's Exhibit 32 specifies that the report should contain the following items:

"(1) Possible alternatives for the disposition of spent nuclear fuel.

"(2) Assessment of cost estimates for the possible alternatives.

"(3) Assessment of ratemaking procedures that account for:

a. Accruing costs currently that will not be expensed until some future date, and its attendant tax implications.

b. Recovery of costs at today's estimates or estimates at some future date.

c. Disposition of accumulated expenses collected by the utility.

d. Vehicle for collecting a possible charge (ECAC or base rates).

"(4) Recommendation on whether enough information is available, to incur a reasonable cost for the disposition of spent nuclear fuel, and if a cost if recommended, a rate-making procedure should also be recommended."

Edison did not contest this staff recommendation. The proposed requirements appear to be reasonable, and the order will require Edison to comply with them.

c. Hydraulic Power Generation

(1) Hydraulic Expenses

For Account 537 Edison used a five-year trend, 1974 through 1978. The staff deleted 1978 because of the unusual rain and snow conditions which occurred during that year. Instead, the staff trended recorded information for the five-year period, 1973-1977. In our opinion the staff correctly excluded the atypical year 1978 from the trended data used for estimating this account. We will, therefor adopt the staff's test year estimate for Account 537, which is $53,00 lower than Edison's figure.

(2) Maintenance of Structures

For Account 542 the staff used the same five-year averaging method that it used for the six nuclear power generation accounts, as discussed above. This resulted in a test year estimate for this account that is $94,000 lower than that of the utility which used a trending method with historical data. We will adopt the staff estimate as reasonable for the test year 1981.

3. Power Production Expenses (Fuel-Related)

a. California Department of Water Resources and Catalina

In the application as filed, Edison included revenues from sales to the California Department of Water Resources (CDWR) together with associated expenses, and it also included fuel costs related to its Catalina electric operations. Edison now agrees with the staff's recommendation that the CDWR revenue and expenses should be handled in ECAC proceedings rather than in base rate increase proceedings. This treatment is consistent with Decision No. 92496, supra. It has no net impact on expenses since the estimated revenues of $7,296,000 are exactly offset by expenses.

Edison further agrees that the $1,212,000 in fuel expenses included in the application for Catalina electric operations should, as recommended by the staff, be excluded from consideration in this base rate proceeding. Those expenses will be covered through the Catalina ECAC procedure, which was established by Decision No. 91561 in Application No. 58331 on April 15, 1980, subsequent to the filing date of the application herein. In Application No. 59830 dated July 23, 1980, Edison, in accordance with that decision, requested recovery of the fuel expenses for the Catalina electric operations.

b. Allocation of Fuel-Related Production Expenses

The staff proposes to disallow from consideration in this base rate proceeding two items relating to allocation of costs between the two regulatory jurisdictions involved in Edison's retail and resale operations, namely, the Federal Energy Regulatory Commission (FERC) and this Commission. These items are identified as "FERC Adjustment" and "Allocation Differences"; they amount to $967,000 and $612,000, respectively. Under the staff proposal they would be dealt with under the ECAC procedure; however, Edison questions this proposal. Because of the nature of these items involving the procedure of allocating costs between the two regulatory jurisdictions, Edison is not convinced that they could appropriately be handled under the ECAC procedure.

Based on our analysis of the problem, including our desire to simplify ECAC procedures, we agree that these allocation matters cannot be appropriately considered in the ECAC procedure; hence, the staff disallowances do not appear appropriate. We will, therefore, adopt Edison's test year figure for Fuel-Related Production Expenses, as adjusted for the CDWR and Catalina expenses described above.

4. Customer Accounts Expenses

a. Customer Records and Collection Expenses

The staff estimate for test year labor expenses for Account 903 is $261,000 lower than Edison's estimate. The staff estimate is based upon 1979 labor costs escalated for wage increases and for growth in number of customers served. The staff witness who prepared this part of the staff estimate pointed up a significant relationship between Edison's collection expenses and its uncollectibles, namely, that when uncollectibles decline, labor expenses for collections may be expected to decline in concert. He noted a marked improvement in uncollectibles over the five-year period 1974-1978 and reasoned that the labor charged to Account 903 should decline in 1979. The recorded 1979 figures for Account 903 show that such a decline did, in fact, occur. Recognizing the validity of this relationship, we will adopt the staff estimate for the labor component of collection expenses rather than that of the utility, which trended for years of recorded expenses as the basis of its estimate.

b. <u>Bill Distribution Expenses</u>

The staff recommends a reduction of $1,381,000 in the test year estimate of postage costs for customer bills as developed by Edison. The record shows that this adjustment resulted from a misunderstanding; therefore, the staff-recommended reduction should not be made to test year expenses. The misunderstanding arose because Edison responded incorrectly to a staff data request. We will not make this reduction in bill distribution expenses.

c. <u>Uncollectible Accounts</u>

The staff estimate for uncollectibles, Account 904, is $135,000 less than Edison's estimate. The staff employed a test year uncollectible accounts rate of 0.233 percent, as compared to a 0.2625 percent rate based upon a five-year average as used by Edison. The lower uncollectibles rate used by the staff is consistent with the utility's recent record of improving collections as discussed above under Customer Records and Collection Expenses. The following figures demonstrate this improvement:

Five-year average write-off (1974-1978)	0.2625 percent
Three-year average write-off (1977-1979)	0.207 percent
Recorded year write-off (1979)	0.205 percent

d. Miscellaneous Customer Accounts Expenses

The staff's estimate for Account 905 is $58,000 less than Edison's. The staff used the approach of escalating 1979 recorded data to the 1981 cost level, rather than following the trending method used by Edison for this account. The staff treatment used here is consistent with the approach it used for Account 903 above. Consistent with our adoption of the staff's test year estimate for Account 903, we will adopt the staff estimate for Account 905.

5. Administrative and General Expenses

a. Public Information Activities

The staff's estimates for public information activities charged to Accounts 920, 921, 922, 930.1, and 930.2, in the aggregate, are $531,000 lower than Edison's. The staff recommends disallowances totaling that amount on the basis that the expenses are not allowable for ratemaking under the criteria enunciated by this Commission in Decision No. 86794 in Application No. 54946, an Edison general rate case decided in 1976.

Included in the $531,000 is a recommended disallowance of $108,000 for Edison's Energy Communications Speakers Bureau. The record shows that $35,000 of the $108,000 was previously directed at company history but has been redirected to oral presentations on renewable energy sources, plant siting, and the environment. The remaining $73,000 is for customer-requested presentations on today's energy issues and their impact on the public. In our opinion the entire $108,000 is an allowable expense and does not fall under the exclusion criteria enunicated in Decision No. 86794.

The staff recommends disallowing $99,000 for management conference meetings. The record shows, however, that the meetings provide Edison's employees an opportunity to come in close contact with management and that the meetings instill positive motivation in job performance. We are of the opinion that the costs of these management meetings are allowable expenses under Decision No. 86794 criteria.

Also included in the $531,000 are recommended reductions of $90,000 for exhibits and displays and $92,000 for energy communications. The first activity relates to conservation and the second activity emphasizes the use of renewable energy resources to generate electricity. The record is clear that the costs of these activities are allowable expenses under Decision No. 86794 criteria.

With respect to career and equal opportunity educational services, the staff recommends the disallowance of $142,000 on the basis that such activities as junior advancement, career education, and advisory activities are not allowable expenses for ratemaking purposes. The evidence indicates that these activities assist Edison in maintaining good relations with and providing assistance to communities it serves. For example, Edison's assistance to members of those communities in entering the job market is an effective way to maintain such relations and provides an overall net benefit to the ratepayer.

b. Affirmative Action Litigation Expenses

The staff recommends disallowance of $173,000 from Accounts 920, 921, and 923 representing salaries and legal fees in defending the Thompson case, an affirmative action class-action suit concerning job discrimination brought against Edison on behalf of minorities. The thrust of the staff recommendation is to disallow for the test year 1981, all identified recorded legal expenses, both in-house and outside costs, relating to the Thompson case.

Edison has offered to settle the Thompson suit for $400,000 and Edison's offer has been found acceptable by the Equal Employment Opportunities Commission (EEOC). However, the record does not show whether the plaintiffs intend to accept this offer. At the time of submission Edison had made no payment in settlement of the suit, and Edison did nc· include any amounts for a settlement in test year expenses.

For purposes of this proceeding, we shall assume that settlement will be made, and on this assumption we shall exclude from adopted test year results all costs incurred by Edison in the Thompson case. It is our position that in an affirmative action suit where settlement has been offered, it would be unreasonable to assume for ratemaking purposes that the offer was made with the sole aim of avoiding the costs of further litigation.

Our treatment of this issue is in harmony with the position taken by the FERC in its Accounting Release No. AR-12, which states that utility expenditures resulting from employment practices which are found to be discriminatory by judicial or administrative decree or which are the result of a consent decree will be classified as non-operating expenses.

c. Canceled and Abandoned Projects

Edison has included $6,955,000 in Account 930.2 as the forecasted test year amortized expenses for canceled and abandoned projects. It is Edison's position that this amount is required to amortize investigatory and development costs incurred in connection with major generating or energy projects which are undertaken to meet projected increases in customer demands for service but which are canceled when the utility determines that for causes beyond its control completion of the projects is not feasible. It is also Edison's position that in subsequent general rate cases, adopted test year results should be appropriately adjusted to reflect the differences between the forecasted amortization level of abandoned project costs already allowed in rates and the level of costs for projects actually abandoned.

Edison alleges that in the period 1974-1979, it recovered through rates less than one-third of the costs written off to abandoned projects and that under previous ratemaking practices no practical way has been open for it to recover the majority of costs written off to abandoned projects. Edison urges that it be allowed to recover through rates all reasonable and prudent expenditures for abandoned projects. It asserts that the forecasted test year amortization level is an appropriate means for recovering such costs through base rates. Edison states that expenditures for projects now in preconstruction stages are reasonable and are being prudently incurred.

The issue before us is not the amount of the item but whether or not it should be allowed. The staff recommends that this item be disallowed in its entirety. The staff refers specifically to Decision No. 87639, a 1977 general rate case order for San Diego Gas & Electric Company (SDG&E), in which the Commission required staff review of amortization-related expenses of abandoned projects. The staff contends, in effect, that no Commission decision requires the treatment Edison is seeking in this case.

Edison contends that the Commission has, in fact, expressed its general position regarding rate treatment for abandoned project costs. It quotes Decision No. 87639 with regard to abandoned projects, as follows:

> "We are convinced that it would be inequitable to disallow expenses incurred as a result of reasonable management action."

Edison interprets this language as indicating the Commission's intent that where prudent expenses are incurred as a result of an abandoned project all of those expenses should be permitted to be recovered through rates. The staff, however, contends that the following language from a 1979 SDG&E rate order, Decision No. 90405, should be considered in conjunction with the foregoing quotation from Decision No. 87639:

> "While recognizing that SDG&E's promotion and development of the Sundesert project was not imprudent, the Commission finds itself neither disposed nor entitled to shield the utility's investors from all risk associated with its new plant investments."

This language comes from our analysis of rate treatment for the preconstruction expenditures for the abandoned Sundesert Nuclear Plant and specifically relates to treatment of the Allowance for Funds Used During Construction (AFDC). In that same section of the decision we also stated:

> "AFDC covers the investor risk when a project is undertaken and carried through to completion. When a proposed project is terminated, and siting and site-related costs are included in plant held for future use and/or amortized, it is proper to exclude the AFDC allowance for investor risk because the project did not come to fruition."

We then disallowed all of the AFDC from rate treatment but allowed essentially all of the other Sundesert expenditures.

Since Edison is not making an issue of AFDC in this application, its position is consistent with that stated above. Edison has excluded AFDC in computing the $6,955,000 in amortization expenses it asks herein to be allowed for abandoned project losses.[5]

Edison's forecast was determined from budgeted preconstruction expenditures in 1981 for projects in preconstruction at the time the application was prepared and on the probabilities of each of the projects' being canceled during 1981. According to the testimony of Edison's witness, the probabilities were based entirely on the judgment of the forecaster. We are not convinced that probability factors so determined constitute a reliable basis for the ratemaking determination of the costs of abandoned projects. We will, therefore,

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5/ Edison emphasizes, however, that it does not agree that accumulated AFDC on a project later abandoned should be disallowed recovery in rates. It contends that these costs are just as prudently incurred and that they are incurred solely on behalf of the ratepayer's interest just as is any other cost reasonably incurred in its attempts to bring new projects on line for meeting the increased demands of the public for service.

not adopt Edison's proposed forecasting procedure, and we will not allow the amount of $6,955,000 in forecasted amortization expenses to be included in test year expenses.

It is not our intention to cause reasonably and prudently incurred expenses to be borne by the stockholder merely because they "slip down the crack" between general rate cases. Rather, our position is simply that the forecasted amortization level methodology proposed by Edison is not acceptable for ratemaking purposes.

6. Depreciation Expenses

The staff's estimate for test year 1981 depreciation expenses is $2,399,000 less than Edison's. This difference results from the following depreciation effects of the staff's disallowance of items of operating plant:

North Brawley geothermal plant	$1,472,000
Distribution plant	197,000
San Onofre Unit 1 Seismic Study	1,565,000
Subtotal	$3,234,000
Offsetting depreciation effects of nuclear decommissioning costs	(835,000)
Total	$2,399,000

Under the heading "Rate Base", infra, we discuss the above staff disallowances. We do not adopt the staff disallowance of the distribution plant item, but we do adopt the staff disallowance relating to the North Brawley plant and the San Onofre unit. At the same time, however, we recognized $21,000,000 in other nuclear plant additions to operating plant, which are depreciable. We also adopt the staff estimate for nuclear decommissioning costs. Accordingly, we will adopt the following adjustment to Edison's depreciation expenses estimate:

North Brawley geothermal plant	$1,332,000
San Onofre Unit 1 Seismic Study	1,565,000
Other nuclear plant additions	(979,000)
Nuclear decommissioning costs	(835,000)
Depreciation expenses adjustment	$1,083,000

In Exhibit 43, the staff addressed various methods of recovering the costs of decommissioning nuclear power plants. The Commission concurs with the staff's conclusion that the estimated net decommissioning costs should be recovered in the depreciation expense and retained by the utility at the present. However, since there still exists considerable uncertainty regarding the subject of decommissioning nuclear power plants, Edison should file in its next general rate application an exhibit assessing any changes in the costs of decommissioning and their impact on the financial integrity of the utility. Such an exhibit should also be filed in any rate base offset proceeding for San Onofre Nuclear Generating Station Units 2 and 3.

7. Taxes

a. Taxes Other Than Income

(1) Ad Valorem Taxes

The difference between the staff's and Edison's estimates relates principally to two aspects of the treatment of ad valorem taxes. One aspect concerns the allocation of the ad valorem taxes. Here the staff used historical costs less depreciation (HCLD) as the basis of allocations and Edison used reproduction cost less depreciation (RCLD). The staff treatment of this aspect produced a figure that is $7,360,000 lower than Edison's. The other aspect concerns the capitalization of ad valorem taxes on construction work in progress (CWIP). The staff capitalized $4,517,000 of such taxes not capitalized by Edison.

Regarding allocation, Edison, the staff, and the State Board of Equalization (SBE) all base their estimates of market value in California on HCLD. SBE, however, allocates the assessed value back to local taxing jurisdictions by an RCLD method. Edison in making its 1981 test year estimate used the RCLD method to remove the capitalized portion of ad valorem taxes. On this point, we quote the staff witness as follows:

> "(The utility)...reflected latest SBE practice by developing an actual assessment ratio by dividing the SBE 1979-80 assessed valuation by the utility's beginning-of-year 1979 HCLD. This factor of 23.2% was then used in developing the estimated assessed valuation for fiscal years 1980-81 and 1981-82. This factor was also used by staff in developing its estimate... Once the utility developed its estimated market value and assessed valuation, it removed the capitalized portion of its ad valorem tax based on the SBE's...RCLD method of allocation. The RCLD allocation has the effect of shifting roughly half of the assessed value of CWIP from CWIP account to operative plant. Because of RCLD allocation, the assessed valuation assigned to CWIP by SBE and used by the utility in its estimate is based on a ratio of 11.36% of HCLD on CWIP rather than the 23.2% referred to previously."

In our opinion, the staff position regarding allocation of ad valorem taxes is correct. It conforms to the treatment we recently afforded this issue in Decision No. 91107 in PG&E's last general rate case. Regarding the aspect of capitalization of ad valorem taxes on CWIP, we will adopt the staff position on this issue. From the evidence presented by the staff, it is clear that CWIP is assessed by SBE at, or very near, HCLD. It is reasonable for ratemaking purposes that CWIP be removed from expenses and capitalized at the current assessed value ratio.

Before this matter was submitted, SBE issued Edison's 1980-1981 revised assessment for ad valorem taxes, and the staff submitted for the record a new estimate of ad valorem taxes prepared in accordance with the new assessment. The new estimate is

$44,294,000, compared to $47,367,000 as originally estimated by the staff and $58,246,000 as estimated by Edison. In our adopted results we will reflect staff's new estimate of ad valorem taxes based on the revised 1980-1981 assessment of SBE.

(2) Payroll Taxes

We will adopt the staff's estimate of test year payroll taxes insofar as it is consistent with labor costs. We are increasing the payroll taxes to reflect Edison's recent wage settlement. This treatment is consistent with our adoption of an allowance for increased wages, as discussed below.

b. Taxes on Income

For test year 1981 Edison has estimated federal and state income taxes at present rates to be $72,174,000. The staff's estimate is $145,255,000 or $73,081,000 greater than Edison's. In large part, this difference relates to the higher level of revenues and lower level of expenses reflected in the staff's estimated results of operations for the test year. There are, however, two major issues relating to the computation of the allowable level income taxes for ratefixing purposes.

The first of these issues concerns the capitalization of ad valorem taxes. The staff computation includes an income tax deduction for this item which is $10,736,000 greater than that used by Edison.

The record indicates that the staff treated this issue correctly, and in our determination of income taxes for the adopted results of operations we will follow the staff recommendation.

The other income tax issue concerns the income tax deduction for repair allowance expense. The staff estimate for the repair allowance deduction for the test year is $45,000,000, whereas Edison has included a deduction of only $25,000,000 for this item in its income tax calculation. This issue arose in Edison's last general rate case, Application No. 57602, in a manner identical except for the amounts involved. In Decision No. 89711 in that proceeding we adopted the greater repair allowance recommended by the staff; however, we permitted Edison to set up a deferred debit in its retained earnings account to accrue any ultimately disallowed optional repair allowance tax deductions which were not recognized in the determination of rates. Edison was authorized to seek amortization of this amount in its next general rate case (i.e., the present proceeding where, significantly, it has not sought such an amortization). Since we have adopted the staff's estimates of repair allowance, this approach is reasonable and we will, once again, adopt this means of making Edison whole if its position on repair allowance deductions is ultimately rejected by the courts.

8. Wage Settlement

Both Edison and the staff used a 7.0 percent annual rate of escalation in developing the labor component of estimated expenses and rate base for the years 1979, 1980, and 1981. Subsequent to the preparation of the application, Edison entered into a wage settlement with the two unions representing the operating workers of the company. As a result of the settlement, which has been ratified by both unions, Edison's workers received a 9.5 percent wage increase effective December 1, 1979 through December 31, 1980.

The settlement with the unions includes a wage package tied to the Consumer Price Index (CPI). The settlement uses a CPI of 224.7 as a reference point, and it has a wage increase ceiling of 13.5 percent.[6] The October 1980 CPI stood at 252.6, and the November 1980 CPI is projected at 255.1. Thus, under the terms of the settlement, the wage increase for 1981 will be 13.5 percent.

Applying the maximum settlement increase of 13.5 percent to 1981 wages would increase the 1981 revenue requirements over those in the filing by about $20,500,000 on a system basis or about $19.9 million for Commission jurisdictional operations.

6/ The summaries under "Pay Standard Compliance" at pages 1-2 and "Price Standard Compliance" at pages 3-5 of Exhibit 10-A demonstrate that a 13.5 percent labor wage increase for 1981 would be in compliance with the revised voluntary guidelines promulgated by the Council on Wage and Price Stability effective October 1, 1980.

Edison takes the position that since these labor increases for 1980 and 1981 are now fixed by contract they should be fully recognized in the 1981 test year cost of service used for fixing base rates. Edison argues that test year estimates using these higher labor escalation rates would be more reasonable for rate fixing than either the estimates in the application as filed or in the showing of the staff. According to Edison it would be appropriate for the Commission to take official notice of the CPI just before this decision is finalized so that the most accurate labor escalation rate could be reflected in the test year estimate adopted for fixing rates.

The staff has used an escalation rate of 7.0 percent and, unlike Edison, it did not modify its showing to reflect the wage increase resulting from the 1980 labor settlement agreement now in force. The staff does not dispute that Edison is actually incurring this higher wage expense; however, it poses the question as to the degree which the Commission should pass through wage increases of this magnitude. The staff expresses concern that a full pass-through would remove an incentive to hard bargaining.

We share the staff's concern; however, we are faced with the necessity of here and now developing a real-world solution which will be equitable to the ratepayer, to labor, and to the utility's investor. We cannot arbitrarily make an out-of-hand refusal to pass through the full increase on the mere concern suggested by the staff. The wage settlement agreement must be examined on its merits. Nothing in this record supports a conclusion that Edison did not bargain effectively or that the wage increase is excessive. Edison has met its burden of proof showing reasonableness of the increase. The agreement meets the Administration's wage and price guidelines, and it is not out of line with other recent significant labor settlements. Edison's increased labor costs are fixed by a contract which is now in effect. In fixing rates herein, we regard it as reasonable to take official notice of the latest available CPI.

In determining adopted test year expenses we will use labor escalation factors of 9.5 percent for 1980 and 13.0 percent for 1981. The use of 13.0 percent for 1981, rather than 13.5 percent, recognizes that management salaries are not set by the union contract.

Our adopted test year figure for pensions and benefits and payroll taxes will include an amount to reflect the higher level of wages.

D. RATE BASE

1. General

The staff's rate base for test year 1981 is approximately $90,000,000 lower than Edison's. The specific components of rate base and the amounts by which the staff is lower are:

San Onofre Seismic Study	$24,815,000
North Brawley Geothermal Plant	3,141,000
Distribution Lines	5,380,000
Operative CWIP	4,660,000
Property Held for Future Use	5,671,000
Fossil Fuel Stock	13,736,000
Working Cash Allowance	34,400,000
Miscellaneous Items	(1,799,000)
Total	$90,004,000

(Red Figure)

2. San Onofre Seismic Study

The staff recommends excluding $24,815,000 from plant representing the test year effects of a scheduled seismic study in connection with San Onofre Nuclear Generating Station Unit 1. Completion of this seismic study has been postponed until the end of 1982. We will accept this disallowance; however, the record shows that there have been some offsetting budget changes for other nuclear capital items to which the staff has not given recognition. These expenditures were required by the NRC as a result of the Three Mile Island incident. They total approximately $21,000,000, and we will make appropriate allowances for them in our adopted rate base.

3. North Brawley Geothermal Plant

The staff reduced its beginning-of-year plant estimate by $3,141,000 on the assumption that an anticipated sale would materialize, whereby the Los Angeles Department of Water and Power (LADWP) would acquire 50 percent of Edison's interest in this developmental plant. Information now available to us indicates that the sale is likely to be consummated. We will, therefore, reflect this reduction in the determination of our 1981 test year rate base.

4. Distribution Lines

The staff deleted $5,380,000 from the test year weighted average plant as a result of a forecast based upon a projection of the historical cost of distribution plant per gross meter addition and a projection of gross meter additions. The staff used, as a starting point on which to add forecasted additions, an Edison estimate for distribution plant as at year-end 1979 which was $20,000,000 lower than the actual figure later recorded for that date. Under the circumstances, the staff's proposed disallowance of distribution plant from rate base is not warranted.

5. Operative CWIP

The staff's estimate of operative CWIP is $4,660,000 lower than Edison's estimate and results from the staff's reduction of the amount of plant additions. We are of the opinion that this reduction is overstated, and we will adopt an adjustment of $2,000,000 to apply to Edison's estimate of test year operative CWIP.

6. Property Held for Future Use

The $5,671,000 difference between the staff's and Edison's estimates for this item relates to six properties previously classified as property held for future use which were either disposed of or properly transferable to nonutility status. We will adopt the staff's figure for property held for future use.

7. Fossil Fuel Stock

The amount of $13,736,000 by which the staff's estimate is lower than Edison's is attributable to different figures for the amount of natural gas available for boiler fuel. The staff obtained from Edison a later forecast which indicated that greater amounts of gas would be available than included in the forecast Edison used in its application. Edison does not contest the staff use of the later gas forecast, but it contends that the staff's should also have used the higher oil price forecast of which it had knowledge at the time.

The record shows that the increase in fuel stock due to this higher price of oil amounts to $26,000,000, which is more than an offset for the rate base effects of the greater availability of natural gas. The record also shows that neither the staff nor Edison reflected in inventory the $87.5 million of oil Edison has in dead storage. Recently, in Decision No. 91107 dated December 19, 1979, concerning a PG&E rate case, we recognized fuel oil in dead storage as part of the fuel oil inventory in rate base.

We are of the opinion that Edison's estimate for the cost of fossil fuel stock to be included in rate base is conservative; therefore, it cannot reasonably be subjected to a downward adjustment.

8. Working Cash Allowance

Edison's estimate of the working cash allowance to be included in rate base for the test year is $287,600,000; the staff's estimate is $253,191,000. The difference arises in large part because of differences in estimates of operating expenses, including taxes. Consistent with the level of estimated operating revenues and expenses we have found reasonable for test year purposes, we will adopt the amount of $215,101,000 for the working cash allowance to be included in rate base. This amount is significantly lower than either of the above estimates because it reflects the effects of the higher income taxes which result from the increased rates authorized herein.

E. JURISDICTIONAL COST ALLOCATION

Because Edison operates under two regulatory jurisdictions, i.e., FERC and this Commission, it is necessary that a jurisdictional cost allocation be made after the system cost of service has been developed. The allocation serves to identify the costs associated with Edison's retail operations and to quantify the deficiency in revenues at present rates from such operations.

The staff cost allocation witness testified that he had examined the utility's jurisdictional cost allocation factors and found them to be reasonable. Edison contends, however, that the staff did not use those allocation factors, with the result that the staff cost allocation improperly disallows transmission-related expense and rate base in the test year. Edison states that the effects on jurisdictional revenue requirements are a little over $3,000,000 as a result of the staff's resale (FERC) demand allocation being too high and another $1.2 million as a result of the staff resale (FERC) commodity allocation factor being too high.7/

We can summarize these differences between Edison and the staff as to jurisdictional cost allocation as follows:

7/ In our discussion under "Allocation of Fuel-Related Production Expenses", supra, we have already considered jurisdictional allocation items involving non-ECAC fuel-related expenses totaling $1,579,000 ($967,000 and $612,000). We resolved these two items in Edison's favor. They are, nevertheless, closely related to the problem of allocation that we are discussing here.

Item	Revenue Requirement Offset $M
(1) Demand-related (fixed cost) differences associated with staff's rejection of Edison's "FERC" adjustment	$3,034
(2) Commodity-related differences relating to staff's alleged omission of losses in computing an energy factor	
(a) Operational and Maintenance Expense Component	554
(b) Income Taxes	32
(c) Rate Base	569
Subtotal	$1,155
Total jurisdictional allocation differences between Edison and the staff (except for non-ECAC fuel-related differences)	$4,189

We have examined the record carefully with respect to this jurisdictional allocation problem, but there is not enough information in evidence for us to make the determination that Edison's revenue requirement should be $4.2 million greater; therefore, we will adopt the staff's allocation with respect to the above items.

We express our concern because it is certainly not our intention to relegate any portion of Edison's legitimate costs to a jurisdictional no-man's land. We urge Edison, in its next general rate case, to come forward and develop the record on this problem in a fully comprehensive manner to provide us with a full set of facts upon which to adjudicate this difference of opinion between it and staff.

IV. RATE OF RETURN

A. GENERAL

Complete showings on rate of return were presented by Edison and the staff. The only other party presenting evidence relating to this subject was the California Association of Utility Shareholders (CAUS). The CAUS presentation deals primarily with the dilution of existing shareholders' equity which has resulted from the issuance of new shares of Edison common stock at prices significantly below book value because of low earnings.

B. COST OF CAPITAL

In Decision No. 89711, dated December 12, 1978, in Edison's last general rate proceeding, we adopted the cost of capital figures relating to Edison's operations for the test year 1979 as shown in Table IV-A.

TABLE IV-A

Cost of Capital
Decision No. 89711

Capital Component	Capitalization Ratio	Cost Factor	Weighted Cost
Test year 1979			
Long-Term Debt	47.84%	7.14%	3.42%
Preferred Stock	13.73	7.29	1.00
Senior Capital	61.57	7.18	4.42
Common Equity	38.43	13.49	5.18
Total	100.00%		9.60%

In the application as filed, Edison requested that we authorize rates which would yield a 15.0 percent return on equity. Using this return on equity, Table IV-B shows Edison's updated projections of the cost of capital in 1981 and 1982 on an average year basis. These projections reflect the revised costs of capital presented at the hearings held following reopening of the matter.

TABLE IV-B

Edison's Cost-of-Capital Projections
1981 and 1982

Capital Component	Capitalization Ratio	Cost Factor	Weighted Cost
Average-Year 1981			
Long-Term Debt	47.00%	8.71%	4.09%
Preferred Stock	13.00	8.02	1.04
Common Stock Equity	40.00	15.00	6.00
Total	100.00%		11.13%
Average-Year 1982			
Long-Term Debt	47.00	9.20	4.32
Preferred Stock	13.00	8.29	1.08
Common Stock Equity	40.00	15.00	6.00
Total	100.00%		11.40%

The staff believes that a 13.6 percent return on equity would be fair and reasonable. Based upon this return, the staff has made the projections shown in Table IV-C for the cost of capital in 1981 and 1982 on an average-year basis. Table IV-C reflects the staff-estimated costs of senior capital presented at the hearings held following reopening of the matter.

TABLE IV-C

Staff's Cost-of-Capital Projections
1981 and 1982

Capital Component	Capitalization Ratio	Cost Factor	Weighted Cost
Average-Year 1981			
Long-Term Debt	47.00%	8.63%	4.06%
Preferred Stock	13.00	8.03	1.04
Common Stock Equity	40.00	13.60	5.44
Total	100.00%		10.54%
Average-Year 1982			
Long-Term Debt	47.00	9.07	4.26
Preferred Stock	13.00	8.28	1.08
Common Stock Equity	40.00	13.60	5.44
Total	100.00%		10.78%

Using Edison's figures for the cost of capital, the requested 15.0 percent return on equity would provide after-taxes interest coverages of 2.72 for 1981 and 2.64 for 1982. Using the staff figures for the cost of capital, the recommended 13.60 percent return on equity would produce after-taxes interest coverages of 2.60 times in 1981 and 2.53 times in 1982.

No issue exists between the staff and Edison regarding the appropriate capital structure for test period purposes. The two parties have used the same capital ratios for both 1981 and 1982.

C. RETURN ON EQUITY

1. General

The United States Supreme Court has established certain tests for determining the adequacy of rate of return to be allowed a public utility. (Federal Power Commission v Hope Natural Gas Company (1944) 320 US 591; Bluefield Water Works and Improvement Company v West Virgina Pub. Service Commission (1923) (262 US 679.) The tests include the following:

> The Comparable Earnings Test. The return to equity holders should be commensurate with returns on investments in other enterprises having corresponding risks.
>
> The Credit Impairment Test: The return allowance should be sufficient to assure confidence in the financial integrity of the utility and not impair its credit.
>
> The Capital Attraction Test: The return allowance should be sufficient to enable the utility to attract capital at reasonable rates.
>
> The Balancing of Interests Test: The return should balance the interests of both the investors and customers of the utility.

2. The Comparable Earnings Test

A comparison of Edison's common stock earnings performance versus a number of comparable groups is shown on Table 9 of the staff's Exhibit 55 and on Table 18 of Edison's Exhibit 1. Both tables demonstrate that during the last five years Edison's earnings on common equity have lagged behind the averages of the other comparison groups. That this is not simply the result of a lower return requirement due to lesser investor-perceived risk is made clear from the comparison of price/book ratios which are available in the record for some of the groups. Table 21 of Exhibit 1 shows that during the five-year period Edison common has experienced considerably poorer market performance than the averages for the comparison groups used in the table.

The earnings/price ratio comparisons between Edison and the comparison groups in Table 20 of Exhibit 1 show similar results in terms of investor attitudes toward Edison and comparable electric utility common stock investments. The comparisons indicate that investors have placed a cost on common equity funds invested in Edison of more than 15 percent on average over the last five years compared with about 12 percent for the comparison groups. These comparisons lead us to conclude that circumstances are now such that the 13.49 percent return on equity which we last authorized Edison would no longer meet the comparable earnings test. Nor would the somewhat higher 13.60 percent return on equity recommended herein by the staff be sufficient to meet this test. Based on what the evidence of record shows, we conclude Edison's requested allowance of 15.0 percent meets the comparable earnings test and appears to be quite near the true cost to Edison of common equity.

3. The Credit Impairment and Capital Attraction Tests

The earnings allowance should seek to enable the utility to issue new shares of common stock without dilution of existing shareholder interests.

The record shows that Edison is now in a marginal position with respect to the retention of its Aa bond rating. While no particular level of return allowance would guarantee its ability to retain the Aa bond rating, Edison's recommended return allowance would provide reasonable assurance that the current bond rating would be retained. On the other hand, it is clear that the staff's recommended 13.60 percent return allowance could not reasonably be expected to provide support for Edison's existing credit rating. Clearly, a higher return is required to meet the credit impairment test.

A major problem facing Edison in the attraction of capital continues to be its inability to sell its common shares at or near book value. Thus, raising capital through the sale of common equity has the effect of diluting the investment of existing shareholders. If it does not do so in absolute terms because of the offsetting value of retained earnings, it does so in relative terms by depriving the investor of the benefit of a substantial part of the earnings on his investment which have been retained by Edison and reinvested in the utility business.

The market performance of Edison's common shares indicates that improved earnings on equity are required to meet the capital attraction test.

4. The Balancing of Interests Test

The application of this test requires recognition that the balancing of the interests of investors and customers is more than a dollars and cents relationship and that the interests of the two groups are not completely inconsistent. For example, society as a whole benefits from the service of a healthy utility industry capable of meeting our reasonable energy needs. Similarly, we all benefit from the achievement of increased conservation and improved load management. The public clearly benefits in terms of both the reduced cost of utility service and greater reliability. Investors benefit by the reduction of the financing requirements for the additional plant required to increase system capacity. Everyone benefits from the reduced consumption of high-cost oil and the decreased reliance on foreign fuel sources.

A balanced regulatory policy gives adequate consideration to conservation and load management while, at the same time, putting the utility in the strongest position reasonably possible to finance the additional system capacity needed to meet the energy requirements of an increasing population which is striving to maintain its standard of living. Such a policy requires that the regulatory authority authorize a return allowance which is commensurate with the true cost of capital to the utility. No different conclusion can be reached

IMAGE EVALUATION TEST TARGET (MT-3)

6″

IMAGE EVALUATION TEST TARGET (MT-3)

6″

even when considering the balancing of the interests of investors and customers in strictly dollars and cents terms. In our opinion an allowance for return on equity in the neighborhood of 15.0 percent reasonably meets the test of balancing the interests of Edison's investors and Edison's customers. We will adopt 14.95 percent as a fair and reasonable return on equity for the two-year period 1981-1982.

D. POSITION OF CAUS

CAUS takes the position that, to meet the standards of the courts and the marketplace, the Commission should find that a 17.0 percent return on common equity and a 12.0 percent rate of return is justified for 1981. CAUS makes this recommendation with the proviso that the Commission make an adequate allowance for attrition during the two-year period that the rates will be in effect.

CAUS asserts that regulation has produced an "imbalance which favors the users of energy over those who risk their money to make that service possible". The only means of correction according to CAUS lies "in an honest recognition of the past seven years during which Edison's stock has sold continuously at discounts of 20 to 40 percent below book value". CAUS urges the Commission "to bite the bullet" and to recognize that the marketplace makes its own judgments "unfettered by the artificiality of divisional distinctions on the make-believe world of pro forma results of operation analysis". CAUS, in asking us to look at the hard evidence, insists that the marketplace is the ultimate arbiter of the cost of money and measurement because in the marketplace the investor faces an initial choice of whether to invest in a regulated or nonregulated enterprise. As the investor becomes more aware of what CAUS calls the confiscation of the property of existing shareholders, he will become less interested in putting his money at risk in a regulated enterprise. CAUS contends that investors are now attracted to utilities only when they can require existing shareholders to give up $1.40 of their interest for each new dollar offered.

According to CAUS, during the period since the Three Mile Island problem, which commenced in March 1978, investors are demanding greater returns from nuclear utilities to compensate for greater risk. CAUS states that this shift in investors' attitude shows up clearly when we compare Edison's price/earnings ratios to those of the average electric utility since 1978. This is shown in Table IV-D.

TABLE IV-D

Price/Earnings Ratios

	Median 100 Electrics (a)	Edison	Edison as % of Median
12/29/78	7.4x	8.1x	109
3/30/79	7.4x	7.5x	101
6/29/79	7.3x	6.3x	86
9/28/79	6.9x	[illegible].3x	91
12/31/79	6.5x	5.4x	83
2/29/80	5.9x	4.7x	80

(a) Source: Electric Utility Common Stock Market Data, Salomon Brothers.

CAUS asserts that the present 13.5 percent allowed rate has been proved entirely inadequate; and that while Edison actually earned slightly more than 13.5 percent in 1979 (the test year for its last rate case), the price of its stock has never sold above 83 percent of its book value since the last general rate case decision was handed down in December 1978. CAUS believes that experience and hard evidence in the marketplace have demonstrated that the 13.5 percent allowed return in the last rate case should have been at least 15 percent.

E. ADOPTED RATE OF RETURN

Although interest rates might recede from the alltime high level experienced by Edison in early 1980, we would be totally unrealistic to adhere to the costs of senior capital which Edison projected when it prepared the application in 1979. We are, therefore, adopting the staff's more recently prepared projection of the year-end cost of senior capital.

Using our adopted figure of 14.95 percent return on equity and the staff year-end projections for debt and preferred stock would provide after-taxes interest coverage of 2.69 times. The adopted cost of capital which results is shown in Table IV-E.

TABLE IV-E

Adopted Cost of Capital
Test Year 1981

Capital Component	Capitalization Ratio	Cost Factor	Weighted Cost
Long-Term Debt	47.00%	8.85%	4.16%
Preferred Stock	13.00	8.15	1.06
Senior Capital	60.00		5.22
Common Equity	40.00	14.95	5.98
Total	100.00%		11.20%

F. ATTRITION OF EARNINGS

Both Edison and the staff recommend that the Commission make allowance for attrition in earnings for the year 1982 following test year 1981. In determining the adopted rate of return of 11.20 percent, supra, we have made allowance for financial attrition by using year-end 1981 cost of capital. This is the equivalent of the average cost of capital over the two-year period 1981-1982. The issue of the larger component of operational attrition is separate and distinct from financial attrition.

Edison recommends that we recognize 1981-1982 attrition by recovering through rates one-half of the estimated dollar amount in each of the years 1981 and 1982. In making this recommendation Edison contemplates that a single set of rates would be effective throughout the two-year period.

The staff proposes to treat attrition in a manner different than heretofore used by the Commission in setting electric rates. The staff points out that, when a given rate of return is authorized for a test year and the rates remain in effect for an ensuing period, earnings will decline if costs during that period exceed those utilized for test year purposes. The effect is to cause earnings to seesaw, rising in years when rate relief is granted and falling during the ensuing periods. The staff would alleviate this problem by a procedure involving stepped rates.[8/] Using this procedure, the order would provide for a level of rates to be effective during 1981 based on test year 1981 results with no allowance for operational attrition. For 1982 the rates would, through an advice letter procedure that would involve further hearings, be increased in one step to a higher level to offset the estimated effects of attrition in 1982 results of operations.

It is the staff position that stepped rates are consistent with the Commission's policy as stated in Decision No. 89711, supra, of setting rates "so that major utilities can reasonably go at least two years without general rate relief". The staff asserts that the use of stepped rates would provide a more stable earnings pattern, which would have a positive effect on the financial community's

8/ Edison is on record as not opposing the staff proposal that the Commission adopt stepped rates.

attitude toward investment in Edison and on the yields required on new debt issues. The staff refers to the fact that stepped rates have been adopted by the Commission in recent general rate proceedings involving major water utilities.

We feel that it would be reasonable and serve a useful purpose to authorize stepped rates in this proceeding. We do not believe, however, that the proposed staff procedure is necessary to give effect after one year to the single-step increase. Following such a procedure, protracted hearings could ensue, and the Regulatory Lag Plan, rather than being facilitated, would be jeopardized. We will, therefore, adopt the staff's proposal to establish stepped rates, but without the requirement for further hearing. The adopted stepped rate procedure is consistent with Decision No. 92497, dated December 5, 1980, in Application No. 59316, in which we authorized Southern California Gas Company (SoCal) a stepped rate increase for the years 1981 and 1982.

Edison will be authorized to file at the appropriate time a one-step rate increase which will distribute the additional revenue requirement as an equal percentage to base rates, except for certain domestic usages as specified later herein.

We are adopting an operational attrition allowance of $91 million to be recovered through the one-step base rate increase that we will allow to become effective January 1, 1982. Table IV-F shows our calculation of this amount.

TABLE IV-F
Calculation of Estimated Operational Attrition

Item	Gross Revenue	CPUC Jurisd.
	(Dollars in Thousands)	
Revenues (From Exhibit 152)		$(16,818)
Operation and Maintenance Expenses		
Labor ($264,647 x 11.25%*)	$29,773	28,624
Nonlabor ($328,049 x 11.25%*)	36,906	35,481
Payroll Taxes (From Exhibit 152)	2,138	2,038
Ad Valorem Taxes (From Exhibit 152)	4,847	4,620
Investment Tax Credit (From Exhibit 152)	2,889	2,743
Rate Base (4,71 ,000-4,529,000**) x 11.20% x 1.715***	35,919	34,290
Total		$ 90,978
Use		91,000#

(Red Figure)

* Average of 9.5% and 13.0%
** From Exhibit 54-A
*** Net-to-gross multiplier (equity)
\# Because of the effects of uncollectibles and franchise requirements, this attrition allowance produces a gross revenue requirement of $91.9 million.

V. ENERGY CONSERVATION AND LOAD MANAGEMENT

A. BACKGROUND

In Decision No. 84902 dated September 16, 1975, in PG&E's Applications Nos. 54279, 54280, and 54281, we identified conservation as the most important task facing the utilities today and stated our intention to make the vigor, imagination, and effectiveness of a utility's conservation efforts a key question in future rate proceedings and decisions on supply authorizations.

In Decision No. 86794 dated December 21, 1976, we authorized Edison to expend the amount of $4,305,000 for conservation programs. We noted that in subsequent proceedings a more detailed analysis of Edison's programs would be undertaken. We required Edison to perform followup studies to determine the effectiveness of its conservation programs, which include an assessment of the efforts to distribute information and to market conservation hardware, with estimates of cost-effectiveness and resulting energy savings. We directed Edison to take the initiative to develop and bring before the Commission programs of incentives, including, and not limited to subsidies, low-interest loans, and modified rates, for inducing conservation-oriented behavior and investment by end-users. We placed

Edison on notice that we would adjust its rate of return upward or downward in subsequent proceedings as the evidence indicated.

In Decision No. 89711 dated December 12, 1978, we authorizes $20,000,000 for Edison's energy management programs (energy conservation and load management). We directed Edison to develop methods for evaluating the persistence of energy savings; to expand the definition of cost-effectiveness for its energy management programs, appropriately reflecting deferred plant savings; and to continue to expand implementation of energy management programs, particularly the Conservation Voltage Regulation program (CVR).

In this proceeding Edison requests $39,000,000 in energy conservation and load management expenses; additionally, Edison requests $436,000 for expenses associated with CVR, exclusive of second phase capital expenditures.

B. EDISON'S POSITION

Edison's conservation policy witness testified that the utility has been committed to conservation for over ten years. He stated that conservation-oriented policies are reflected throughout Edison's activities, and that its senior management has for some time used various oversight committees to support these policies. The witness summarized the various techniques used in estimating conservation program savings, noting that overall potential for conservation in the service territory has not been addressed. He expressed the opinion that determination of the overall potential would be a very difficult task, since it depends largely upon individual motivation to conserve.

Edison's proposed 1981 test year budget of $39,000,000 represents a 48 percent increase over the amount allowed in its last general rate case. The witness stated that $25,000,000 will be used to fund Edison's "base" programs, which consist of a mixture of residenital and nonresidential programs for both conservation and load management. The additional $14,000,000 is requested to fund "supplemental" mandated programs, including the Residential Conservation

Services program (RCS) mandated by the National Energy Conservation Policy Act (NECPA); the Residential Load Management Standard mandated by the Load Management Standards adopted by the California Energy Commission (CEC); the End-Use Surveys required by Title 20 of the California Administrative Code which are utilized by the CEC in the Biennial Report/Common Forecast Cycle; maintenance of the Standard Industrial Classification (SIC) Coding for nonresidential customers; below market rate financing for insulation and solar water heating systems; expanded promotional activities for solar in both new construction and retrofit of existing dwellings; and an apartment cogeneration project. Edison also anticipates $436,000 in additional CVR expenses associated with voltage surveillance requirements. Edison projects for 1981 and annualized energy savings of 2,021,457,900 kWh and demand reduction of 252.6 MW from successful implementation of its customer-oriented programs, as well as, additional 1981 savings of 1,600,000,000 kWh from its CVR program.

Another Edison witness presented the details of the utility's proposed 1981 base conservation plans and programs within ten major categories of activity: Nonresidential Conservation, Nonresidential Load Management, Cogeneration, Residential Conservation, Residential Load Management, Solar, Public Awareness, Advertising, Measurement, and Management in Conservation and Load Management Activities.

In the Nonresidential Conservation Activity category, Edison will continue its commercial; industrial, agricultural, and public authority energy audit program. The audit effort will be augmented by mailing self-help audit information to new commercial/industrial customers, presenting Energy Management Awards to businesses and industries who have made outstanding conservation efforts; utilizing a mobile display of conservation hardware applications; offering an electric water heater thermostat turn-down service; encouraging HVAC and electrical contractors, refrigeration mechanics and technicians, and wholesale suppliers, to promote conservation hardware at the time of equipment servicing; and promoting conservation hardware through a coupon incentive campaign. Edison will support its Agricultural and Water Pumping Test program with a Pump Test and Adjustment program which requires deep well turbine pump customers to have a contractor present to make the appropriate adjustments at the time of the Edison pump test. Edison will also offer a free feasibility study for utilizing heat recovery equipment in milking parlors with electric water heaters.

In the Nonresidential Load Management category, directed at its commercial, industrial, agricultural, and public authority customers, Edison will continue its evaluation of off-peak systems and utility-activated load cycling systems for contribution to peak demand reductions. The submetering and analysis of nonexperimental and experimental time-of-use rate designs will also be continued.

In the Cogeneration category, Edison will continue to encourage the installation of cost-effective on-site generation by commercial and industrial customers, which can be operated in parallel with the Edison system for the benefit of all ratepayers. The potential for residential cogeneration and customer-owned auxiliary generation is also being investigated. In addition, Edison is also working with several customers who are planning to develop cogeneration projects using biomass, landfill methane recovery, or solid waste conversion.

In the Residential Conservation category, efforts will include a revised new customer booklet containing self-help audit information; a computer audit activity (SAVES); an in-home audit activity (Sherlock) supported by small group meetings (Conservation Workshops); a master meter apartment/mobile home park activity; a toll-free Conservation Information Line that allows non-English-speaking customers to ask a talking computer conservation load/management questions in any programmable foreign language; an evaluation of the cost/benefit of expanding communication efforts with Spanish-speaking customers; participation in the National Energy Watch program; an animated mobile van show; a series of public service television programs, related to conserving energy in the home; and Conservation Corner, a hardware/device showroom. Ongoing conservation hardware-oriented activities will include Home Insulation program; and

Wrap Up II, which will continue to offer electric water heater customers free water heater insulation blankets and low-flow shower heads. New programs feature De-Light, a program promoting the use of low wattage light bulbs; Secondary Refrigerator Reduction, a program designed to remove inefficient refrigerator/freezer equipment from the marketplace; Energy Efficient Appliance program, designed to expand public awareness on the avilability of energy efficient appliances that exceed state appliance efficiency standards; and Off-Peak Refrigerator Development, producing and merchandising a new energy efficient refrigerator. The Residential Activity for 1981 will also include a number of technical support and energy-use research activities.

In the Residential Load Management category, Edison will emphasize utility-activated load cycling experiments, time-of-use rate experiments, new meter developments, a swimming pool pump deferral effort, several off-peak cooling tests, and a consumer education load-shifting campaign utilizing the theme "Give Your Appliances the Afternoon Off".

In the Solar category, Edison's objective is to (1) encourage builders of new housing developments who have elected to install electric water heaters to also install solar water heating systems, and (2) to make solar end-use device information available to existing homeowners with electric water heaters to encourage retrofit solar applications.

In the Public Awareness category, Edison's efforts encompass eight major components directed at reinforcing consumer awareness of the vital need for conservation and load management, including conservation/load management communications materials (slides, brochures, etc.) which are used with educators, students, professional organizations, governmental agencies, resale customers, and the general public.

In the Advertising category, Edison's activities include (a) the development of thematic general public awareness conservation advertising for placement in newspaper, television, and radio media to reinforce the conservation ethic and provide specific conservation suggestions for saving electric energy, and (b) advertising directed toward support of and consumer acceptance of specific conservation/load management programs.

In the Measurement category, Edison's activities include reports, special studies, research, and personnel necessary to quantify results from specific conservation/load management programs. They also include econometric measurement which employs multiple regression analysis to isolate the impacts of major economic variables on the consumption of electricity.

The Management of Conservation/Load Management Activities category includes the expenses and associated costs incurred by management and administrative personnel.

In addition to its direct presentation on its conservation programs, Edison takes issue with the staff's recommendation for a rate of return reduction. The specific arguments surrounding this issue will be discussed at length in the section entitled, "Negative Adjustment to Rate of Return". Edison also takes issue with staff's recommendations reallocating funds from residential, solar, and general awareness programs to (1) increase the funding of the nonresidential audit and Agricultural Time-of-Use programs, and (2) create a conservation contingency fund. Furthermore, Edison believes that the requirement for Commission approval prior to making any conservation program change larger than $300,000, recommended by the staff, is too restrictive and burdensome.

C. POSITION OF THE STAFF

1. Energy Conservation Programs

The staff showing covered the areas of quantitative measurement, individual program analysis, and overall conservation program evaluation. The staff recommends no overall reduction from the $39,000,000 that Edison has requested in this proceeding; however, the staff recommends reallocating $2,866,900 from Edison's proposed program budget to increase the agricultural Time-of-Use and Non-residential Energy Audit programs, as well as to create a Conservation Contingency Fund. The staff further recommends imposition of a $20 million penalty in the form of a rate of return reduction for inadequate conservation efforts. Staff recommendations in specific areas are discussed below.

a. Quantitative Measurement

The staff recommends that Edison continue with its initial efforts to improve the behavioral assumptions underlying the engineering estimates used in its disaggregate analysis. The staff also recommends that Edison prepare a detailed proposal for a study of its Wrap Up II program, employing either and end-use econometric or paired comparisons approach; Edison should then complete the study as proposed.

The staff recommends that Edison rigorously pursue the development of end-use date which provides detailed information concerning the saturations of energy-using devices and the physical, demographic, and other characteristics of customers in the residential, commercial, and industrial classes; Edison should use and end-use econometric model on a pilot basis to analyze this data when it becomes available.

The staff further recommends that Edison undertake surveys about the persistence of energy savings. Such study should consider whenever possible the way in which savings build up, remain constant, or decline over the life cycle. The staff notices that in Decision No. 89711, the Commission recommended that Edison develop methods for evaluating the persistence of energy savings. The staff believes that Edison should be much farther along in developing such methods than is the case.

The staff also recommends that Edison verify its Sherlock Homes Program savings estimates within six months. Finally, the staff recommends a budget allocation of $1,044,600 for 1981 test year measurement expenses.

b. Program Analysis

The staff recommends a total reduction of $2,866,900 from the following areas: deleting four Residential Conservation programs, deleting one Solar program, reducing the level of funding for Public Awareness programs, and reducing the level of funding for General Advertising. The staff recommends, however, increased funding of $1,000,000 for both the Agricultural Time-of-Use Rates program and Nonresidential Energy Audit programs. In addition, the staff recommends establishing a Conservation Contingency Fund of $1,866,900, to initiate new programs and/or accelerate existing or proposed programs as required in the test period. The staff qualifies the use of this fund as not being usable for general advertising or public awareness programs.

The staff bases its recommendations for reallocating funding in the manner described above on its comparison of Edison's estimates of program cost-effectiveness and productivity. The staff notes that Edison's large and small nonresidential energy audit programs which account for over 82 percent of the total quantifiable estimated energy savings, have utility cost-to-savings ratios below one-half cent per kilowatt-hour saved. On the other hand, the staff's evaluation indicates that a number of Edison's proposed residential energy conservation programs are duplicative or excessively funded. The staff notes that the majority of Edison's measurable residential programs are funded at levels corresponding to utility cost-to-savings ratios well over one cent per kilowatt-hour saved.

The staff also recommends that Edison consider cooperating with SoCal in providing a share of the weatherization training program for the Comprehensive Employment Training Act (CETA) employees to prepare them for work on the RCS program.

C. Evaluation of Overall Conservation Programs

The staff recommends a reduction of $20 million in Edison's 1981 test year revenues in consequence of Edison's failure to adequately pursue energy conservation.

The staff further recommends that, after a six-month period subsequent to the effective date of a decision in this proceeding, the punitive return adjustment be rescinded if Edison has met certain minimum specified requirements. The staff would require that Edison:

> Undertake all studies needed to determine the potential for energy conservation in both the residential and nonresidential sectors.
>
> Accelerate Phase II of the CVR program.
>
> Expand its very small nonresidential audit program and develop ways to improve the results achieved by all nonresidential energy audits, giving consideration to the use of financial incentives where appropriate.
>
> Implement all recommendations included in the staff reports titled, "Report on the Quantitative Measurement of Southern California Edison Company's Conservation Programs Test Year 1981" and "Analysis of Energy Conservation Programs of Southern California Edison Company Test Year 1981". (Exhibits 111 and 112, respectively.)
>
> Make application for authority to provide zero-interest financing for all cost-effective residential conservation measures.
>
> Expand its cost-effectiveness guidelines to include the full marginal cost of electricity and submit a report on the guidelines to the Commission.

Develop and propose to the Commission a concise definition of cost-effectiveness and a methodology for determining the cost-effectiveness of energy conservation programs.

Develop and submit to the Commission a schedule for its study of the energy conservation potential and the resulting expansion of its energy conservation efforts.

2. Load management

The staff recommends adoption of the Edison-proposed programs with the addition of the above-described agricultural time-of-use rate experiment.

The staff further recommends that unspent funds should be transferred to the next year's budget. However, the staff witness pointed out that this is a dynamic area and it may be necessary to review levels of spending from time to time and that his recommendation would best serve present purposes. Edison may seek necessary but unfunded amounts through a CLMAC filing; it should not be allowed to retain unspent amounts.

As a result of the agriculural rate experiment recommended by the staff, some $750,000 less revenue will be gained from the agricultural class due to the off-peak incentives. The staff recommends the deficiency be made up within the agricultural class consistent with the resolution of a similar situation by the Commission in PG&E Decision No. 9107, supra.

D. DISCUSSION

In Decision No. 91107 dated December 19, 1979 in PG&E's Applications Nos. 58545 and 58546 we reiterated our commitment to the promotion of energy conservation and the use of alternative energy resources. We stated in unequivocal terms: "Where the marginal cost of conserved energy is less than the marginal cost of new supply, the former should always be the investment of chocie." (Mimeo p. 152.) We stated that we expected the energy utilities we regulate to make these principles central in their planning and investment decisions. We repeat that admonition here, because we believe that there is a large conservation potential in Edison's service teritory that has not yet been tapped and because we are not convinced that Edison's 1981 Energy Conservation program effectively realizes this potential.

1. Conservation Goals

By letter dated January 2, 1980, Edison was directed to "state your goals for accomplishing market saturation of cost-effective conservation programs within a reasonable time frame." Edison interpreted this directive as a request for its goals for individual hardware-oriented programs and incorporated its response in data supplied to the staff. These goals were reported by staff in its Exhibit 112.

There is evidence to suggest that Edison's conservation goals are too low. The calculations of program cost-effectiveness, Exhibit 112, indicate that the effective conservation cost to its customers in cents per kilowatt-hour is, for nearly all programs in all projected years, much lower than present estimates of the incremental cost of electricity. It is likely that many, if not all, of such programs could be significantly expanded without surpassing the cost-effectiveness limit.

Additionally, but perhaps most disturbing, is the fact that Edison indicates a lack of an overall conservation strategy in its response to our January 2, 1980 directive. Edison's use of goals appears limited to targets set for its existing programs during the test years under consideration. In Decision No. 91107 we indicated our intent that energy conservation be a resource central to utility resource planning. A piecemeal approach to conservation goal-setting is not exemplary of Edison's dedication to this principle.

We recognize that the staff in this proceeding has not provided any analysis of appropriate conservation goals; however, it is our belief that this is essentially a utility management function and the initial effort at least ought to come from Edison. We initiated a staff program in Decision No. 91107 to develop, update, and monitor progress toward definable goals for PG&E. We will do the same in this proceeding for Edison. These goals will be used to evaluate Edison's conservation program performance in the next general rate case.

In establishing specific goals, Edison should be guided by the following overall goal: All currently cost-effective conservation potential shall be achieved to the level of effective market saturation by 1986. This is five years after the test year in this case, and eleven years after we stated our intention to make the vigor, imagination, and effectiveness of a utility's conservation efforts a key question in future rate proceedings and decisions on supply authorization.

Some conservation technologies are likely to achieve effective market saturation more rapidly than others. For any cost-effective conservation technology for which Edison feels it cannot achieve effective market saturation by 1986, or for any program it believes is not cost-effective to pursue further increments of market saturation, it will be required to make a convincing showing to this Commission. Shifts in emphasis will be granted on a case-by-case basis.

With respect to Edison's goal setting, we direct it to do the following:

> Develop and submit by October 15, 1981, and annually thereafter, projection of conservation goals for its programs. The submission shall clearly indicate both its evaluation of what constitutes effective market saturation for each technology for which it has identified potential and its goals for achieving such saturation in each sector of its service territory.

We recognize that the likelihood of achieving conservation potential will vary among markets. Edison's statement of goals must clearly reflect an examination of projected and actual market responses, as well as program cost-effectiveness.

2. Conservation potential

Conservation potential is the quantity of energy that could be saved if every possible cost-effective conservation action were taken by all parties. Although potential is difficult to measure and is dependent upon savings to date, it is a measurable quantity, independent of public attitudes or customer willingness.

Edison indicated on the record that, except for a limited residential device study[9/] and an end-use survey for the commercial

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9/ This study was performed during the first quarter of 1980 at the specific request of the staff.

sector, it has not performed a conservation potential study for its service territory. Edison attributes much of its inaction to an uncertainty as to the definition of conservation potential.

We are greatly concerned about the impacts of Edison's conservatism in this area; knowledge of the total potential conservation available in any market sector is basic to setting goals for conservation. Once potential conservation is established, the likelihood or expectation of achieving it can be factored into the equation to develop forecasted savings.

With respect to conservation potential we direct Edison to:

> Develop and submit by June 15, 1981, and annually thereafter, a clear statement of electric conservation potential in each sector of its service territory (i.e., residential, commercial, industrial, and by priority group). It is desirable that the statement be based on experimental data to the maximum extent possible. Areas of uncertainty and the sensitivity of the final estimate to that uncertainty must also be identified.

3. Cost-Effectiveness

Edison uses the average cost equivalent of oil as its cost-effectiveness guidelines, using this to approximate its "incremental cost" of fuel savings. Edison asserts that this approach is justified since most conservation programs save energy not capacity. We do not agree that such an approach is necessarily correct; a great deal of conservation occurs in intermediate peak, if not full peak, conditions. Furthermore, any savings which occur continuously erode the peak as well as off-peak requirements.

In Decision No. 91107 we indicated that it was the marginal cost of energy against which conservation programs were to be compared. For an electric utility this marginal cost includes some component of demand; we agree, however with the marginal cost-effectiveness level will vary according to when the savings occur. We fully recognized the complexity of the question when, in Edison's last rate case, we ordered Edison to confer with the staff in developing a cost-effectiveness measure which reflects a demand component. We are concerned to find that Edison does not seem to have developed more sophisticated criteria for determining cost-effectiveness than the average cost equivalent of oil.

We therefore direct Edison to:

> Develop by June 30, 1981, a cost-effectiveness methodology which fully reflects the marginal cost of electricity saved by its conservation programs. Such a method should reflect the appropriate components of avoided capacity, energy, and transmission/distribution charges which correspond to electric savings made on-peak, mid-peak, and off-peak.

The staff's review of Edison's programs indicates that all but three meet its present cost-effectiveness criteria of 5.34¢ per kilowatt-hour. In fact, the staff Exhibit 112 indicates that programs responsible for 82.5 percent of the estimated savings have a cost-to-savings ratio much less than one cent per kilowatt-hour. Such a comparison strongly suggests to us that Edison's conservation effort can be expanded cost-effectively.

4. <u>Measurement of Conservation Savings</u>

Tied hand-in-hand with cost-effectiveness is measurement of conservation program savings. As discussed previously, Edison uses two methods, aggregate econometric analysis and disaggregate analysis, to measure overall savings and program specific savings (respectively). There are substantial limitations to each approach. We do note, however, that Edison's recent experimental work with a newer technique, end-use econometric modeling, looks promising. Therefore, we direct Edison to:

> Continue to pursue for each major sector an end-use econometric modeling effort, including specific variables to represent energy conservation devices and activities and using at-the-meter consumption data.
>
> Specifically address the behavioral assumptions underlying estimates of savings through completing a comprehensive behavioral study of appliance utilization rates and patterns by December 31, 1981.
>
> Submit a detailed proposal by June 30, 1981, for a study on the Wrap Up II Program, using either econometric or paired comparison approaches (described in Exhibit 111) unless another approach can be clearly demonstrated to be superior. The study should be completed by December 31, 1981.
>
> Augment residential end-use data with detailed information concerning the saturation of energy-conserving devices by June 30, 1981.
>
> Complete end-use studies concerning the saturation of energy-using devices, and the physical, demographic, and other characteristics of customers in the commercial and industrial sectors by December 31, 1981.

The measurement of energy conservation also depends on an analysis of energy savings persistence. We note that in Decision No. 89711 we directed Edison to develop methods for evaluating the persistence of energy savings. The record indicates that it took Edison until 1980 to initiate the development of a plan for data collection; we are concerned that future efforts be completed in a more timely manner. Therefore, we will direct Edison to:

> Complete a study of the persistence of electric energy savings and demand reduction for the residential sector by December 31, 1981. Complete a study of the persistence of electric energy savings and demand reduction for the commercial and industrial sectors by June 30, 1981. The study of persistence should consider the way in which savings will build up, remain constant, or decline over the life cycle of conservation activity or hardware.

We also take note of the impact of customer behavior on measureable savings attributable to Edison's programs. The staff in its review of Edison's measurement program discusses only in general terms the significance of market research programs. We feel a more comprehensive evaluation of Edison's market research efforts is appropriate at this time. Therefore, we will direct Edison to:

> Submit to the Executive Director, within thirty days of the effective date of this order, one copy of each of its market research studies for the years 1977, 1978, and 1979. Where the research was performed for Edison by an outside consulting firm, a copy of the consultant's final report will constitute the market research study. Where the research was performed by Edison's staff, a copy of the final staff report or other documents discussing and analyzing market survey data will constitute the market research study.

Submit to the Executive Director, by June 1, 1981, one copy each of its market research studies for the year 1980.

5. Conservation and Load Management Programs

Edison has included a total of $39,000,000 for the expenses of its proposed energy conservation and load management programs[10/] for test year 1981. The staff does not contest this amount, which includes $25,000,000 to cover base programs and $14,000,000 earmarked for supplemental programs mandated by this Commission and the CEC, as well as NECPA. We shall adopt $39,000,000 for the test year estimate of Customer Service and Informational Expenses.

The staff, while agreeing with the proposed level of expenditures for the test year, recommends a number of changes relating to the character and scope of the programs. Table V-A presents a summary of Edison's proposed test year programs and the modifications thereto as recommended by the staff in Exhibits 111, 112, and 115. Table V-B presents a complete list of conservation/load management base and supplemental program expenses recommended by the staff in Exhibit 112.

10/ This level of expenses includes the costs of certain programs mandated by the federal government and other state agencies, are, for accounting purposes, entitled "Customer Service and Informational Expenses" and are booked in Accounts 907 through 910, as prescribed by the FERC.

Edison requests $2,348,100 for public awareness programs. These are support activities which by themselves do not generate any quantifiable energy savings, therefore the cost-effectiveness of these programs cannot be measured. The staff recommends reducing Edison's request by $770,000, down to $1,578,100 on the basis that Edison's requested sum is more than is necessary for public relation activities considering Edison's past efforts and expenditures. Edison contends that the full amount is needed to sell conservation and load management to the public. Edison's request is unsubstantiated in the record. We adopt the staff's recommendation.

Edison requests a total of $5,666,500 for advertising expenses. Of this amount, $2,666,500 is allocated to individual program advertising, and $3,000,000 is assigned to general advertising. The expense for general advertising is divided into three areas:

(1) $1,369,000 for an emergency summer capacity program,
(2) $841,000 for a winter fuel oil shortage program, and
(3) $790,000 for contingencies.

The staff recommends reducing Edison's request by $1,500,000 on the basis that the emergency summer capacity ads can be incorporated with the "Give Your Appliance the Afternoon Off" program ads, for which $1,585,000 has been alloted for program advertising. Edison argues that the full amount is necessary in order to respond to "crisis" situations which Edison anticipates occurring in the next few years. We concur with the staff's recommendation. Based on the record we shall adopt the staff's recommended program expenditure levels set forth in Table V-B.

TABLE V-A

Summary of Energy Conservation and Load Management Programs Showing Staff-Recommended Changes
Test Year 1981

Program	Utility Conservation	Utility Load Management	Staff Conservation	Staff Load Management	Utility Exceeds Staff
Nonresidential Conservation	$ 4,751,500	-	$ 5,251,500	-	$ (500,000)1/
Nonresidential Load Management	-	$1,256,600	-	$ 1,756,600	(500,000)2/
Cogeneration	275,000	817,600	275,000	817,600	0
Residential Conservation	15,408,600	-	14,864,900	-	543,700 3/
Residential Load Management	235,000	7,888,400	235,000	7,888,400	0
Solar	1,193,700	-	1,140,500	-	53,200 4/
Public Awareness	2,348,100	-	1,578,100	-	770,000 5/
Advertising (General)	3,000,000	-	1,500,000	-	1,500,000 6/
Measurement	1,044,600	-	1,044,600	-	0
Management of Conservation/Load Management Activities	780,900	-	780,900	-	0
Conservation Contingency Fund	0	-	1,866,900 7/	-	(1,866,900)
Subtotal	$29,037,400	$9,962,600	$28,537,400	$10,462,600	0
Total	$39,000,000		$39,000,000		0
Conservation Voltage Regulation	$ 436,000		$ 436,000		0

1/ Staff recommended additional funding for all nonresidential conservation energy audit programs.

2/ Staff recommended additional funding to implement the agricultural time-of-use rate program.

3/ Total cost of four residential conservation base programs recommended for deletion by the staff. These programs are: Conservation Information Line, National Energy Watch, Mobile Conservation/Load Management Show, and Home Insulation.

4/ Cost of the solar retrofit base program recommended for deletion by the staff.

5/ Staff recommended reduction from the total level of funding requested by Edison for public awareness programs.

6/ Staff recommended reduction from the total level of funding requested by Edison for general advertising.

7/ The residual dollars in Edison's program after staff recommended program deletions and reductions. The staff would have Edison use the money in this "fund" to initiate new programs and/or accelerate existing or proposed programs.

TABLE V-B

Staff-Recommended Conservation/Load Management Programs and Levels of Funding

		Estimated Annual Cost
NONRESIDENTIAL CONSERVATION PROGRAMS		
1.	Energy Audits -- Large (over 200 kW)	$1,516,600
2.	Energy Audits -- Small (20-200 kW)	1,763,400
3.	Energy Audits -- Very Small (Under 20 kW)	526,800
4.	Commercial/Industrial Mobile Display	153,400
5.	Hardware Program	145,600
6.	Turn Down	57,800
7.	Conservation Means Business	46,400
8.	Commercial/Industrial New Customer Conservation Booklet	41,900
9.	Agricultural and Water Pump Test Program	361,200
10.	Pump Test and Adjustment	115,600
11.	Milking Parlor	7,800
12.	Pumping Efficiency Study	15,000
13	Recommended additional funding for all of the above programs	500,000
	Subtotal:	$5,251,500
NONRESIDENTIAL LOAD MANAGEMENT PROGRAMS		
1.	TOU -- General Service Rate Experiment	$137,700
2.	TOU -- Rate (over 5,000 kW demand)	39,100
3.	TOU -- Rate (1,000-5,000 kW demand)	44,700
4.	TOU -- Rate (500-1,000 kW demand)	33,000
5.	Commercial/Industrial Air-Conditioning Cycling	806,900
6.	Commercial/Industrial Off-Park Cooling	101,200
7.	Commercial/Industrial Ice-Making Heat Pump Test	94,000
8.	Recommended Additional Funding for Agricultural TOU Rate Experiment	500,000
	Subtotal:	$1,756,600

		Estimated Annual Cost
COGENERATION PROGRAMS		
1. Residential Cogeneration		$ 275,000
2. Cogeneration Contracts		162,800
3. Cogeneration Studies		654,800
	Subtotal:	$1,092,600
RESIDENTIAL CONSERVATION PROGRAMS		
1. Sherlock		$1,369,600
2. Conservation Workshops		302,400
3. Master Meter Apartment/Mobile Home Park		139,200
4. Saves		776,000
5. Hispanic Program		40,400
6. Residential New Customer Conservation Booklet		227,100
7. TV Conservation Specials		321,500
8. Conservation Corner		473,800
9. Wrap Up II		1,404,800
10. De-Light		49,700
11. Secondary Refrigerator Reduction		770,200
12. Energy Efficient Appliance		265,900
13. Off-Peak Refrigerator		258,800
14. Appliance Retrofit Research		540,200
15. Efficient Appliance Use Test		40,000
16. Research on Consumer Energy Use Patterns		263,800
17. Heat Pump/Water Heater Test		64,200
18. Waste Oil		194,300
19. Residential Conservation Services		7,313,000
20. Insulation Financing		50,000
	Subtotal	$14,864,900
RESIDENTIAL LOAD MANAGEMENT PROGRAMS		
1. TOU Domestic Rate Experiement		$107,900
2. Automatic Powershift -- Laguna Hills		36,400
3. Automatic Powershift -- Valencia		109,900

	Estimated Annual Cost
RESIDENTIAL LOAD MANAGEMENT PROGRAMS (cont'd)	
4. Automatic Powershift -- Systemwide Test	$ 325,300
5. Energy Economizer I	77,100
6. Energy Economizer II	57,100
7. Swimming Pool Pump Program	235,000
8. Residential Off-Peak Cooling Test	61,200
9. Residential Water-Cooled Air-Conditioning Unit Test	30,000
10. Load Management Instrumentation Hardware Testing	500,000
11. Give Your Appliances the Afternoon Off	1,625,500
12. 8 Percent Residential Load Cycling Test	4,958,000
Subtotal:	$8,123,400
SOLAR PROGRAMS	
1. Solar New Construction	$ 79,800
2. Solar/Wind Cost Study	25,700
3. Solar Retrofit	342,000
4. Solar New Construction (Supplemental)	643,000
5. Solar Financing	50,000
Subtotal:	$1,140,500
PUBLIC AWARENESS PROGRAMS	
1. Conservation Services	*
2. Educational Support Services	*
3. Exhibits and Displays	*
4. Public and Employee Communications	*
5. Speakers Bureau	*
6. Speech and Educational Materials	*
7. Workshops, Seminars, and Forums	*
*Subtotal:	$1,578,100

		Estimated Annual Cost
ADVERTISING		
1. General Advertising		$1,500,000
	Subtotal:	$1,500,000
MEASUREMENT		
1. Program Measurement		$ 675,600
2. System Maintenance and Surveys		369,000
	Subtotal:	$1,044,600
MANAGEMENT		
1. Conservation/Load Management Activities		$ 780,900
	Subtotal:	$ 780,900
	PROGRAM TOTAL:	$37,133,100
CONSERVATION CONTINGENCY FUND		$ 1,866,900
RECOMMENDED TOTAL LEVEL OF FUNDING:		$39,000,000

These authorized conservation program expenditure levels for 1981 are substantially higher than Edison's past conservation budgets. In order to protect the ratepayer and assure that monies authorized for energy conservation are expended in a cost-effective manner, we expect Edison to maintain appropriate conservation budget account records so that such expense items may be separately identified, thereby enabling the Commission to monitor expenditures and in the next general rate case to make the necessary adjustments for authorized funds (collected from ratepayers) not spent during the 1981-1982 period. Edison should coordinate its accounting and recording format with both the Financial Analysis Section of the Revenue Requirements Division and the Conservation Branch of the Utilities Division.

The staff recommends that Edison cooperate with SoCal in providing a share of the weatherization training program for CETA employees to prepare them for work in the RCS program. We agree that Edison should work cooperatively with SoCal in implementing such a training program for its service territory; however, Edison's efforts should clearly augment, not replace SoCal's existing training program.

6. Conservation Contingency Fund

We adopt as re~sonable for test year 1981 a contingency fund of $1,866,900. We believe a fund of the above amount is reasonable since there is . real possibility Edison will be required to implement certain programs not otherwise allowed for in 1981 rates. The fund may be used to (1) implement a Summer Peak Contingency program, if necessary; (2) augment the RCS plan if there is a higher customer response for energy audits than allowed in the adopted estimate; (3) start up a zero-interest financing program for residential weatherization; (4) establish a weatherization training center; and (5) implement other programs deemed necessary by Edison and the staff. Expenditures authorized under the contingency fund will be spent only on the designated program and Edison will be required to provide a full accounting of such amounts.

However, we stress that no conservation contingency funds may be used unless prior approval has been received from staff for amounts up to $300,000. Such approval must be in writing upon the signature of the Executive Director. For amounts in excess of $300,000 in a single year, prior Commission approval must be obtained. Unexpended funds will be subject to refund.

7. <u>Energy Conservation Assistance Program</u>

By letter dated December 11, 1979, the Commission's president requested that Edison consider filing an application for a zero-interest financing program for residential weatherization. The staff in this proceeding specifically recommended in Exhibit 116 that Edison be required to file an application for zero-interest financing as a condition for removal of its recommended penalty. Additionally, Edison requested continued funding of its 8 percent attic insulation loan program. It is clear that Edison, the staff, and this Commission are convinced of the need for weatherization of buildings to conserve energy.

The staff, in this proceeding, expressed its desire to promote energy efficient appliances. In Exhibit 116 the staff recommended "the use of incentives to encourage the purchase of energy efficient appliances". The staff further stated "An example of such a program would be the mailing to residential customers of coupons good towards the purchase of a refrigerator which meets or exceeds a minimum energy efficiency requirement." We agree that Edison should use incentives, where cost-effective, to promote the purchase of energy efficient appliances.

In recent years energy costs have risen dramatically. As a result, utility bills have increased substantially and may continue to do so in the future. Additionally, Edison is a summer-peaking utility so it is especially important to reduce summer peak loads by reducing the amount of energy used for refrigeration and air conditioning. We are concerned that customers in those portions of Edison's service area which experience extremely high summer temperatures will be burdened by the high cost of refrigeration and air conditioning. We will therefore direct Edison to submit a program for energy conservation assistance to customers in areas of extremely high summer temperatures. The program should focus on improved weatherization and more efficient refrigeration and air-conditioning appliances.

9. Shifts of Conservation and Load Management Funds

The staff, in Exhibit 116, recommended that "Edison should be required to obtain prior Commission concurrence or approval for any redirection of conservation or load management funding of $300,000 or more". This was intended to ensure Commission awareness and approval of any major redirection of conservation or load management funds. Edison, in its rebuttal testimony, recommended the dollar limit for Commission approval be 5 percent of the total conservation/load management expenditures. We agree with the staff that prior

Commission concurrence or approval should be sought for any redirection of conservation and/or load management funds over $300,000 in a single year.

Expenditures authorized herein will be spent only on the designated programs and Edison will be required to provide a full accounting of such amounts.

No funds exceeding either $100,000 or 10 percent of the authorized level of any program may be diverted from such program to other programs unless prior approval has been received from staff for amounts up to $300,000. Such approval must be in writing upon the signature of the Executive Director. For amounts in excess of $300,000 in a single year, prior Commission approval must be obtained. Unexpended funds will be subject to refund.

E. DEFICIENCIES IN EDISON'S PROGRAMS

The staff was generally critical of past conservation efforts of Edison citing lack of managerial commitment to conservation, lengthy delays in planning and implementing programs, lack of goals, and lack of criteria to measure cost-effectiveness. The staff specifically addressed Edison's efforts in the following areas:

1. The utility has not estimated the energy conservation potential in the residential and nonresidential sectors.
2. The utility does not use the full marginal cost of energy in evaluating and designing energy conservation programs.
3. The utility has a policy which limits its total energy conservation expenditures to the amount authorized in the last rate proceeding.
4. The utility did not promptly initiate a study of persistence of energy conservation programs subsequent to Decision No. 89711 dated December 12, 1978.
5. The utility does not propose to increase its efforts under the CVR (Conservation Voltage Regulation) program by expansion of its Phase II construction program.

Each of these alleged deficiencies will be discussed in detail.

1. Failure to Identify Energy Conservation Potential

The staff asserts that the utility has failed to study energy conservation potential in the residential and nonresidential sectors. The staff cites such a study as being basic to any comprehensive assessment of utility goals for conservation programs. The staff asserts that Edison has been neither aggressive nor imaginative in this respect.

Edison states that the determination of overall conservation potential is a difficult undertaking. Edison is not, however, opposed to developing an estimate of conservation potential and, in fact, expresses the belief that such a study might be beneficial. Edison expresses the opinion that, nevertheless, it is not in the best interest of its ratepayers to spend large sums of funds to conduct a conservation potential study before an appropriate methodology can be agreed upon. Edison does not believe that such an agreement has yet been achieved.

According to Edison, it is incomprehensible that the staff would recommend the imposition of a financial penalty based even in part on Edison's not having conducted a conservation potential study inasmuch as the utility has never been ordered to conduct such a study and no other utility has completed such a study. Edison points out that the only study under way by a utility is one which PG&E initiated after it was ordered to do so by Decision No. 91107, issued December 16, 1979 in its last general rate case.11/

We take note of Edison's efforts in compiling data for the residential and nonresidential markets, and its initiation of end-use surveys in the residential and nonresidential sectors. However, as we discussed previously, Edison has clearly not performed an adequate assessment of conservation potential for its service area.

11/ In Decision No. 91107, PG&E was criticized, but the financial penalty which was imposed on PG&E by that decision was not based on deficiencies in this area.

Determination of the potential is, as the staff contends, the essential first step in developing productive energy conservation programs. It is the basis for conservation goals around which programs are designed. Without a potential study, many opportunities for conservation may be missed due to ignorance of their existence. Additionally, significant ratepayer funds may be wasted on programs which are not needed or are larger than required.

We agree with Edison's contention that there ha been some confusion as to a single definition of the energy conservation potential. However, the lack of a universally agreed upon definition of the potential is no excuse for Edison's inactivity in this matter. Edison should have adopted its own definition and proceeded to estimate the potential. It could then have used it in developing its conservation programs. The fact that no other utilities have previously completed a potential study and that we have not previously ordered one is no excuse.

2. Failure to Use Full Marginal Cost in Conservation Planning

The staff asserts that Edison does not properly reflect the full marginal cost of energy in evaluating and designing energy conservation programs. The staff refers to Edison's statements in Exhibit 4 regarding cost-effectiveness criteria:

> Lacking a concise universally accepted definition of cost-effectiveness, Edison considers a program to be cost-effective when it can be implemented for less than the cost of providing new supplies.

Edison explained its use of "new supplies" in a response to the staff data request:

> At the time Application No. 59351 was developed (mid-year 1979), "new supplies" was considered by Edison to be the incremental cost of purchasing oil.

It is the staff's position that conservation programs are cost-effective if the marginal cost of conserved energy does not exceed the full marginal cost of electricity. The staff asserts that the Commission has explicitly stated that the full marginal cost of electricity includes deferred costs of plant, environmental effects, and fuel charges; that, clearly, Edison's "cost of new supplies" is not equivalent to the full marginal cost of electricity; and that, notwithstanding, the utility has insisted that the incremental cost of oil, or even the average cost of oil, is the correct cost-effectiveness guideline. The staff concedes that any programs which meet the utility's "average-cost-of-oil" guidelines are cost-effective, but that use of such a guideline could serve as an excuse for Edison to fail to pursue programs which are in fact cost-effective relative to the full marginal cost of new supply. The staff further contends that Edison's use of the marginal or the incremental cost of oil is inconsistent with its position on this record to the effect that electricity, even off-peak, includes a value for demand and thus a capacity cost.

Edison counters that the staff witness making this allegation fails to distinguish programs which have no demonstrated reduction in peak demand from those which have peak demand reductions associated with them. Edison has indicated demand reduction for only four of its 54 conservation programs. Edison states that it correctly uses (1) the marginal cost of energy to evaluate the cost-effectiveness of conservation programs having no associated demand reductions, and (2) the marginal cost of energy and demand to evaluate the cost-effectiveness of load management programs.

Edison asserts that the staff witness errs in concluding that the Commission has a clear definition of the marginal cost of electricity. Edison cites the text of its last decision as an indication of the problems associated with defining cost-effectiveness criteria. Edison also believes that the Commission should consider the use of avoided cost concepts in defining cost-effectiveness in a similar manner as avoided costs are used in setting prices for cogenerated electricity. Edison states that the staff witness failed to even consider the use of avoided costs in his cost-effectiveness calculations.

As we stated previously, we do not agree that Edison's present cost-effectiveness guidelines are correct. Edison's use of the incremental cost of purchasing oil as is cost-effectiveness standard is contrary to our long-standing policy that "a conservation activity is worthwhile if it costs less than the full cost - including environmental effects - of supplying the energy which would be saved". While we recognize the complexity of developing a cost-effectiveness measure which accurately reflect capacity and energy savings, we do not condone Edison's simplistic solution of the problem.

3. Limiting Conservation Expenditures to Authorized Amounts

The staff asserts that Edison has a policy which limits its total energy conservation expenditures to the amount authorized in the last rate proceeding.

The staff argues that Edison is not performing in harmony with the Commission's emphasis on conservation in adhering to a company policy of spending nothing on conservation in excess of the levels which have been authorized by the Commission. The record in this proceeding shows that with respect to 1982, Edison intends to spend on its conservation programs no more than the level adopted for test year 1981 unless additional amounts are authorized by the Commission.

The staff concludes that Edison regards the overall expenditure levels for conservation authorized by the Commission as a "conservation allowance" to be spent to the extent possible within the discretion of management; that Edison regards this "conservation allowance" as a level of funding which is both a floor and ceiling on its conservation spending; and that Edison will exceed the overall level of funding for conservation only if the Commission first authorizes additional increased rates.

The staff argues that the expense estimates employed in ratesetting are not intended to be absolute budgetary limits for each expense item; Edison should transfer funding from low priority uses, if more funding is required for high priority uses, like conservation activities. The staff concludes that holding the conservation expenditure level to previously authorized funding erodes the effective funding level (due to inflation), requires expanding some conservation programs at the expense of others, and prevents Edison's gearing up for overall expansion of conservation efforts until after a general rate increase.

The staff concludes that Edison's policy of limiting its total conservation expenditures to the level allowed in the Commission's most recent decision is: (1) contrary to the Commission's directive to make energy conservation central to sound utility management and responsibility; (2) restrictive to timely expansion of existing energy conservation programs and implementation of new conservation programs; and (3) neither indicative of nor conducive to a vigorous or productive conservation effort.

Edison disagrees with the foregoing conclusions regarding the impact this policy has on its commitment to conservation and its ability to conduct a vigorous and productive conservation effort.

Edison points out that conservation expenditures are normally expensed and not included in rate base and that, if a utility is to recover these expenditures, they must either be included in an offset filing or in a general rate case. Edison states that, consistent with the treatment of other expensed items (except fuel), it has generally included conservation and load management expenses in its general rate case filings. Edison recalls, however, that it has previously spent more for conservation and load management than it has been allowed to recover in rates.

The offset filing is, nevertheless, a proper vehicle for obtaining funds for the acceleration or expansion of conservation and load management programs. Edison has, in fact, filed two such offset filings in 1980. Edison states that such filings demonstrate that, when it has determined that additional funds are needed for its conservation programs, it is willing to request such additional funds by the use of the offset procedure and subject its request to the public hearing process.

Edison believes that the staff's suggestion that it transfer funds from other operating expenses to use for worthy conservation programs has little viability. Edison contends that, as a result of its zero-based budgeting process and the staff's thorough review of all expense items, there simply are few, if any, funds available in so-called low-priority operating uses to be transferred for use in conservation programs. The staff did not provide any examples of low-priority uses where such a transfer could be made. We must reject this element of the staff's critique.

We do, however, note that the $91 million allowance for operational attrition authorized by this decision is intended to compensate for increases in all operating expenses, including those of Edison's conservation and load management programs. We therefore expect Edison to increase its conservation and load management budget for calendar year 1982 to reflect the effects of inflation.

4. Failure to Study Persistence of Conservation

The staff asserts that the utility did not promptly initiate a study of persistence of energy conservation programs subsequent to Decision No. 89711, dated December 12, 1978.

It is the staff's position that evaluation of the amount and duration of conservation is essential information in developing conservation programs and that such an evaluation is crucial to the assessment of program productiveness. In this connection the staff cites Decision No. 89711 as follows:

> Edison should develop methods for evaluating the persistence of EM programs, giving consideration to the customer survey changes recommended by the Energy Commission to evaluate EM savings, to measure the effectiveness of its programs.

The record shows that during 1980 Edison will initiate the development of a plan for data collection and analysis to determine the persistence of conservation. The staff believes that the utility should not have taken more than a year to begin to "initiate the development of a plan" to determine the persistence of energy savings. According to the staff, Edison had accumulated a substantial amount of data on its energy conservation program results prior to the issuance of Decision No. 89711, and Edison could have used this information as the basis for a persistence study. The staff contends that it was not necessary for Edison to wait until 1980 for a data base to be developed before engaging a contractor to do a persistence study. The staff points to this type of delay as not being indicative of a strong management commitment to energy conservation.

Edison responds by saying that it recognizes the value of a conservation persistence study and that it intends to conduct such a study at an early date. Edison states that developing such a study is an exceedingly complex problem which must be solved by means of an orderly process which it has been pursuing since 1978. Edison relates that one aspect of this problem is the need for a common data base and that Edison has had to revise its reporting system accordingly. Edison states that it finalized its plans during 1979 for the implementation of the program during 1980.

The record shows that Edison has made some progress towards beginning a persistence study. However, it should not have taken over a year for Edison to initiate the development of a plan for data collection and analysis to determine persistence of savings. Edison's progress with its persistence studies has been too slow.

5. Failure to Expedite CVR Program

The staff asserts that the utility does not propose to increase its efforts in Phase II of the construction program related to the CVR program.

The purpose of the CVR program is to reduce electric energy and capacity requirements. The program involves reducing the maximum allowable customer-service voltage from 126 volts to 120 volts, or as low as possible, while maintaining a minimum customer-service voltage of 114 volts. Lowering the voltage reduces the customer's energy consumption and achieves improvements in motor, lamp, and appliance service. The CVR program is being implemented in two phases. Phase I, which has been completed, reduced the maximum allowable customer-service voltage to 122 volts where possible, while maintaining the 114-volt minimum. Phase I was accomplished without significant capital investment, primarily by making adjustments to existing transmission and distribution equipment. Phase II, which is underway, will complete the reduction of the maximum customer-service voltage to 120 volts when possible. Phase II will be achieved by making necessary capital improvements wherever it will be cost-effective.

The staff stated that "at this time neither the utility nor the staff knows how many circuits can be cost-effectively improved under Phase II of the CVR program". The record shows that there are no circuits on Edison's system which have been identified as being cost-effective for Phase II construction that are not currently being brought into compliance.

It is not clear from the evidence to what degree Edison's Phase II CVR efforts can be expanded. Additionally, it appears that Edison seriously misinformed the staff on this matter. This misinformation led the staff to believe that Edison could expand its Phase II construction program if sufficient construction personnel were available. Edison should make every effort to improve communications with the staff so that it is not unintentionally misled in the future. To this end Edison should continue to file quarterly reports with the Commission on its progress with Phase II of CVR.

In order to determine what remains to be done with Phase II, we shall order Edison to evaluate 1,000 distribution circuits for Phase II capital improvements and report the results therefrom by July 1, 1981. Similarly, we shall order Edison to evaluate the balance of its circuits and report the results by December 31, 1981. This is consistent with a similar requirement placed on PG&E in Decision No. 91107, December 19, 1979. These reports shall include an aggressive plan for construction of all cost-effective CVR Phase II improvements.

Edison believes that its use of spot checks indicates the voltage ranges normally received by its customers. Edison also believes that its monitoring of a representative sample of its circuits constitutes adequate voltage surveillance. The purpose of voltage surveillance is to ensure that the voltage range achieved under CVR is retained on every circuit. Edison's spot checks and representative sample may indicate the voltage level achieved by the utility as a whole. However, they cannot be depended upon to identify individual circuits in need of adjustment. Therefore, we shall order Edison to immediately undertake a voltage surveillance program to monitor the maximum and minimum customer service voltage received on each of its distribution circuits. This is consistent with the voltage surveillance programs currently carried out by all other regulated electric utilities in California pursuant to Commission orders or agreements with the staff.

6. Conclusions

The record shows that Edison has implemented a variety of energy conservation programs. However, the previous discussion shows that Edison has not done all it reasonably can to pursue energy conservation. In particular, Edison has been slow to implement our directives in Decision No. 89711, e.g., accelerating the Phase II CVR program, energy savings persistence studies, and analysis of an appropriate cost effectiveness measure.

Furthermore, the utility has repeatedly countered staff criticism with the arguments that: (1) no one else has done it before and (2) the Commission did not order Edison to do it. We are not moved by these arguments. We do recognize that the development of productive and cost-effective utility energy conservation programs has involved, and will continue to involve, a learning process for the utility, the staff, and ourselves. However, we have noted a limited management commitment to conservation. In making this observation, we are cognizant of Edison's individual program efforts, but we are also cognizant that these individual efforts lack a well-thought-out, long-term goal driven by top-down direction and priority.

Because we do not wish to dampen or discourage Edison in its conservation efforts, we shall not adopt the staff's recommendation that a penalty be assessed at the beginning of the test year. Edison should be on notice, however, that there is a very real cost associated with failure to conserve or to effect conservation. That cost is borne most often by the ratepayer who pays more in his electric bill for excessive use, and who pays for larger new supply projects as more and more electricity must be supplied. From now on, there will also be a cost to the shareholders associated with failure to conserve. We will review Edison's conservation achievements at the conclusion of the test year to determine whether it has met the goals we set forth herein. If it has not met them, we will assess a penalty to reduce rates by $5 million per year.

We do not expect to use this procedure routinely; we use it here because it appears a reasonable response to the concern that there is no standard against which to measure reward or penalty for achievement in the conservation arena. We establish it here, for this proceeding only, because Edison has not developed concrete goals of its own from which to work. Should we see this condition persist in the next general rate case, we would expect to make a negative adjustment in Edison's rate of return at the beginning of the test year.

The goals which Edison must meet to avoid a penalty are as follows:

> Edison shall meet its projected goals of 2,022 billion kilowatt-hours and 252.6 MW for annualized energy savings and demand reduction, respectively, for its customer-oriented base and supplemental conservation and load management programs. Edison shall also meet its goal of 1,690 billion kilowatt-hours savings for its system conservation programs (including CVR).
>
> Edison shall submit a statement of electric conservation potential for its service territory (as described above) by June 15, 1981.
>
> Edison shall submit a statement of goals for achieving, by 1986, effective market saturation of all currently cost-effective conservation potential by October 15, 1981.
>
> Edison shall submit a description of its cost-effectiveness criteria (as described previously) by June 30, 1981.
>
> Edison shall submit data collection and measurement studies as described in Pages 90-92 by the dates indicated therein.
>
> Edison shall report on its findings regarding the cost-effectiveness of making Phase II CVR improvements on 1,000 circuits by July 31, 1981; it shall report on its evaluation of the balance of its circuits by December 31, 1981. Edison shall continue to file quarterly reports on its Phase II CVR efforts.
>
> Edison shall submit its plan for implementation of its voltage surveillance program by April 1, 1981. Edison shall have voltage surveillance in place on each of its circuits by December 31, 1981.

> Edison shall expand its very small nonresidential audit program and develop ways to improve the results achieved by all of its nonresidential energy audits, giving consideration to the use of financial incentives where appropriate. Edison shall submit a report on program implementation by December 31, 1981.
>
> Edison shall submit plans by January 31, 1981 for implementing a zero-interest financing conservation program. Edison shall make a zero-interest financing program, within the finding limitations authorized herein for the Residential Conservation Services and the Conservation Contingency Fund, available to customers in those portions of its service territory exposed to extremely high summer temperatures by April 1, 1981.

Should Edison have failed to meet the goals stated above by the conclusion of the test year, we shall assess a penalty of $5 million per year. We will establish the conditions for removal of the penalty at the time it attaches, giving consideration to circumstances as they exist at that time.

VI. PRICING OF ELECTRICITY

A. GENERAL

The main issue relating to pricing of electricity in this proceeding is the relationship of marginal cost and cost recovery by customer groups. The staff's view is that marginal costs should be used to the exclusion of embedded costs. Edison's view is that both embedded costs and marginal costs should be used.

The staff states that it was the only party in the proceeding to develop marginal costs and use them as the basis of rate design. The staff believes that its use of marginal cost is consistent with the rate design principles enunciated by the Commission in deciding the last general rate cases involving PG&E and Edison (Decisions Nos. 89711 and 91107, respectively.)

A number of the rate design proposals on this record were presented in concept only. They lack the specific details of quantitative rate design and adequate consideration of such important aspects of rate design as revenue stability and conservation cost-effectiveness. Thus, these conceptual recommendations can be considered for specific implementation only to the extent that such concepts may be embodied in the complete rate design proposals presented by Edison and the staff.

A number of interested parties representing Edison's larger commercial and industrial customers actively participated in the rate design portion of this proceeding. Their showings, for the most part, concentrated on the various theoretical rate design concepts being considered, the most significant being, of course, marginal cost pricing. As a group, these large electricity users opposed marginal cost pricing, largely because of concern that it would be applied to impose disproportionate cost burdens on customers with relatively high load-factor loads in a manner not justified by the utility's pattern of cost incurrence.

Our discussion of specific differences of rate design will focus mainly on the showings of Edison and the staff because only their showings included definitive rate proposals for the utility's full array of customer groups and rate schedules.

B. USE OF MARGINAL COST IN PRICING

1. Staff Position on Marginal Cost Pricing

The staff believes that wherever feasible electricity prices should be equal to marginal cost and that otherwise they should at least be based upon marginal cost. The staff in Exhibit 46 has proposed rates reflecting marginal cost in this proceeding, and it advances the following rationale in support of its position:

> "Rates which promote the most conservation, efficiency and equity must ultimately be based on marginal costs. The result of basing rates on marginal costs is that the rate equals the cost of producing one more unit, or the savings from producing one less unit. In this way each

consumer pays the resource cost (additional cost of the added quantity) of additional consumption, or saves the resource cost when consumption is reduced. Conservation is achieved since consumption is made only when the benefits of consumption are greater than or equal to the cost (i.e., there is no 'wasteful' use). Efficiency is achieved since the least cost combination of resource neither over-uses the good (which would occur if its price is below marginal cost) nor under-uses the good (which would occur if the price is over the marginal cost). Finally, equity is achieved since no customer underpays or overpays relative to the resource cost (e.g., consumers choosing solar or insulation are not treated inequitably since they save the resource cost from their lack of consumption and the non-solar or non-insulation electric consumers pay the resource cost for their choice to consume)."

* * *

"Additionally, the rationale for using marginal cost is well-grounded in economic theory. Specifically, the theory states that pricing goods and services at marginal cost will lead to optimal efficiency in the production and distribution of goods within the economy. While competitive processes within the economy would lead to the pricing of goods at marginal cost for the majority of goods, this is not so for goods produced by firms in the regulated sector. Prices charged by regulated firms should be at marginal cost.

"While the economic theory supporting marginal cost pricing is somewhat technical, such pricing can be supported in another way. Marginal costs measure the cost of additional resources which Edison will use to provide electric power to customers. A customer faced with the marginal cost of electricity and the cost of other goods is able to make a rational decision regarding how society's resources are to be directed; he or she will weigh the resource of electricity and alternative goods and choose the combination of goods which provide the greatest service at lowest cost.

"Suppose, for example, electricity were priced lower than its marginal cost. A consumer would be led to undervalue electricity. The response would be to purchase additional electricity and, thus, funnel resources into its production beyond those that could have been allocated to its production had the resource cost been known."

2. Edison's Position on Marginal Cost Pricing

Edison expresses the belief that marginal cost theory cannot be applied "fully or literally" to the electric utility industry. Edison acknowledges, however, that certain concepts involved in marginal cost pricing can be applied advantageously to electric utility ratemaking as, for example, in giving price signals to consumers as a device for achieving conservation and load management objectives. In its opening brief, Edison states its view as follows:

" . . . To the extent that the concept can be applied to portions of the utility's filed rates which represent charges for usage that is the most price responsive and without producing excessive overall revenues which would result in a windfall to the utility, such a concept of price signaling to consumers can be applied effectively.

"The revenue constraint necessarily involves setting some rates below the embedded cost of service or recognizing additional revenue requirements that, if met, will not produce additional earnings above the level found by the Commission to be sufficient to cover the utility's cost of capital. Any rates set below the embedded cost of rendering service, by definition, would amount to a subsidized rate which, if applied to usage that is relatively price elastic, would be counterproductive to the conservation and load management objectives implicit in the use of marginal cost of pricing in other portions of the tariff."

The staff asserts that Edison did not use the marginal cost-based rates it developed for this proceeding, but instead relied, as it has done in the past, on embedded cost as the primary consideration in its rate design. Edison accuses the staff of mischaracterizing its position on marginal cost and in rebuttal states, "So that there can be no doubt, Edison's position is that marginal costs are, and can be, a useful tool as one factor to consider in rate design, but marginal costs are not the only factor to consider in rate design."

Edison, in turn, characterizes the staff position thus: "Generally the staff's approach to the use and calculation of marginal cost is to force it to fit, no matter what."

In Exhibit 12 Edison expresses the following reservations regarding marginal cost-based rate design:

> "At the present time, marginal cost-based rate design does not enjoy industrywide acceptance for several reasons:
>
> "(a) The economic theory claims that marginal cost-based prices would lead to the most efficient allocation of resources. In reality, this optimal allocation of resources may be undermined due to 'second best' considerations - the notion that other scarce resources may not be priced according to their marginal cost;
>
> "(b) no one generally accepted methodology exists for calculating marginal costs;
>
> "(c) customers may not readily understand marginal cost-based prices and it may simply appear to be a way of increasing the price of electricity;
>
> "(d) rates based on marginal costs do not easily lend themselves to the revenue requirement constraint."

In the same exhibit, Edison encapsulates its position on the appropriate uses of average and marginal costs in rate design as follows:

> "1. The cost of service will be the basis for spreading the revenue requirement.
>
> "2. Average costs for energy and demand are the basis for rates, where possible.
>
> "3. Marginal costs of energy and demand can be used in rate design to set the upper limits for rates and to give time-of-use signals."

C. DETERMINATION OF MARGINAL COST

1. General

Marginal cost may be defined as the change in total cost which results from a change in output. For an electric utility, the components of total cost are demand costs, energy costs, and customer costs. A unit of output may be a kilowatt, a kilowatt-hour, or a customer month. Each of the components of cost includes an appropriate allocation of operation and maintenance expense, administrative and general expenses, taxes, plant, and working capital.

For purposes of selecting a methodology which will be meaningful in determining marginal cost for designing electric rates, Edison and the staff actively participated in the task force of the statewide Marginal Cost Pricing Project (MCPP). This project was jointly coordinated by the CEC and this Commission, and it was partly funded by the Department of Energy. The MCPP task force reviewed a number of methodologies including the "Scenario Methodology", which was developed by Edison. The task force reached a general consensus as to the marginal cost methodology to be used to determine marginal cost for electricity. This methodology is before the Commission for its consideration in OII No. 67.

The steps involved in the marginal cost studies of the type made by Edison and the staff for this proceeding include determination of the following: costing periods, generation demand cost, generation energy cost, transmission cost, distribution demand cost, and customer costs.

2. Costing Periods

The cost of supplying electricity is not constant throughout the day or the season. The cost of supplying increased use at a time of high system demand, for example, is greater than an increase in use at a time of low system demand. Similarly, there are differences in energy costs. Generally, utilities dispatch generation units in order of efficiency, with high-efficiency units being dispatched first, followed by units of lesser efficiency. As a result, marginal energy costs are generally higher during on-peak periods than during off-peak periods. Since it is impractical to establish costs and rates for each hour of the day, costing periods are selected.

The selection of costing periods is based upon the grouping together of continuous hours reflecting similar cost and demand characteristics, since costing periods reflect the relative level of controllable costs and the importance of the load level to system reliability. Costing periods are updated from time to time by analyzing reliability measures, diurnal cost, and daily load shapes. There is no commonly accepted method for determining costing periods. The staff methodology recognizes four methods for use singly or in combination. Edison uses two of these methods and two of its own methods of analyzing costing periods. Edison does not recommend that any one be considered by itself. The four methods used by Edison are: excess-load probability, probability of contribution to demand, load-duration curve, and average daily load curve.

At the present time Edison is using in its filed time-of-use tariffs the following costing periods as defined by this Commission.

Twenty-Four Hour Clock Time

	Summer	Winter
Off-Peak	1-7; 22-24	1-7; 22-24
Mid-Peak	8-11; 18-21	8-16
On-Peak	12-17	17-21

3. Generation Demand Cost

In the determination of generation demand costs, perhaps the most crucial as well as most controversial part of a marginal cost study, both Edison and the staff used the Scenario Methodology as developed by Edison. There are, however, significant differences among the assumptions that the two parties incorporated into their respective scenarios.

For determining the marginal costs of generation, the Scenario Methodology conforms to the utility planning processes. It produces estimates of actual cost changes by time periods resulting from postulated load changes and recognizes real-life planning, operating, financial, and regulatory constraints. As developed by Edison, the steps in the Scenario Methodology for determining generation demand costs are:

a. A "base-case" or most likely forecast of load and resource requirements is made.

b. The base-case load shape is modified to become a scenario by making a slight reduction in load over a specified period, in a manner significant for rate design purposes.

c. The impact of the changed load shape on the installed base-case capacity is determined in order to serve the load at the same reliability as established by the base-case.

d. Resource plan changes are identified in order to reduce the installed capacity to the level indicated by step c.

e. The new total cost of serving the scenario load is computed to obtain the change in cost between base-case and the scenario for each year in the forecast horizon.

f. The levelized equivalent to the differential stream of costs from step e. is calculated. The marginal cost is determined by dividing the levelized annual cost by the original load change to obtain annual cost per kilowatt.

By identifying scenarios appropriate for use in rate design (i.e., peak, off-peak, seasonal, etc.), a cost matrix by time period is developed at the generation level. When the generation costs are added to transmission and distribution costs, which are derived using regression analysis, a reasonable approximation of the marginal cost of supplying an additional unit of demand is obtained.

Edison expresses some concern about the stability of the marginal demand costs developed for this proceeding by the staff, as well as those it developed itself. The concern relates to the validity of the basic assumptions used to compute the marginal demand costs. To focus on this problem, Edison refers to the following statement in the staff's opening brief:

> "The Staff first determined the change in generating capacity which would result from a change in system load. The second step was to determine the type and cost of generation resources which would accommodate each costing period's allowable change in capacity."

Edison points out that at the time when the staff and Edison developed the scenarios for their respective marginal cost showings, Edison's resource plan had a combustion-turbine generating plant programmed within the next 10-year period. The resource plan was subsequently changed, and that generating plant now appears as a contingency resource. This could mean that in the second step referred to in the quoted statement the staff has assumed the wrong "type and cost of generation resources" for determining this critical element of marginal cost. The staff counters that Edison has based its calculations partly on a fuel cell, the cost and availability of which are quite uncertain and that, further, Edison has assumed the cost of the fuel cell to be equal to that of a combustion turbine, which is unlikely. The staff states that it does not regard the resulting costs to be reliable and therefore it substituted a combustion turbine for Edison's cancellation/deferral scenario. In any event, the staff and Edison's marginal generation cost calculations yield about the same results. We will regard them as usable for rate design purposes in this proceeding because the differences do not exhibit the wild fluctuations which may result from making different assumptions in the determination of marginal costs.

4. Generation Energy Cost

The marginal cost of energy is derived from the recorded "system lambda" or the system incremental fuel cost. The system incremental fuel cost is defined as the fuel cost incurred to generate the next increment of energy and is expressed in terms of mills per kWh. To determine the marginal cost of energy, the recorded system incremental fuel cost is multiplied by the projected escalation factor for that year. The escalation factor is calculated from the forecasted increase in the average price of oil. Both Edison and the staff calculated marginal energy by using the 1978 recorded fuel cost multiplied by an escalation factor of two.

The staff observed that "there may be refinements as further methodological work is done on the calculation of energy costs."

We are concerned that Edison's current estimates are not based on all units Edison dispatches to meet changes in load. This results in marginal costs which are not reflective of the actual experience on the system and which are poor costing data for conservation decisions. The data presented by the staff will be used as the best available, but Edison is hereby put on notice that in future rate proceedings it should present better marginal energy costs. The costs should include all generating units used by Edison to follow load, and they should reflect seasonal as well as daily variations.

5. Transmission Demand Cost

Transmission plant falls into two categories: (1) transmission facilities dedicated to serve specific generating plants and (2) transmission facilities not so dedicated. The first category of transmission plant is considered to be generation-related and is excluded from the determination of the marginal cost of transmission.

Edison calculated the marginal cost of nongeneration transmission in two ways, by an incremental method and by a least-squares regression method. The staff used only the regression method in a manner consistent with its recommended marginal cost methodology in OII No. 67.

In the incremental method, the future costs of additional transmission facilities are analyzed with respect to changes in the system peak demand. The marginal cost of transmission is defined as the total cost in constant dollars of the incremental plant additions for a period of years divided by the increase in peak loads. In the regression method, transmission demand costs are determined by regressing the cumulative investment in constant dollars against the cumulative change in peak load for a period of years.

Both Edison and the staff used data for the 12-year period ending 1979, using 1981 dollars throughout. Edison estimated transmission demand costs of $7.44/kW/year by its incremental method and $6.86/kW/year by its regression method. The staff estimated the transmission demand cost to be $10.30/kW/year using its regression method.

6. Customer Costs, Including Distribution Demand Co

The marginal cost of distribution is related to two factors, the number of customers and the characteristics of distribution demand. Stated in other words, customer costs are those costs which increase with the number of customers, and the distribution demand costs are those distribution costs which increase with the customer demand. According to this concept, the customer-related portion of the distribution system costs are extracted from the net total distribution plant investment on the basis of a hypothetical "minimum distribution system", the equipment component of which changes only with the number of customers. The remainder of the investment in the net distribution plant is treated as distribution demand costs.

Distribution demand cost is the same for all customer groups. Total distribution demand cost is derived from the remaining portion of the net distribution plant investments after deducting the investment required for the aggregate minimum distribution system.

Marginal customer costs are determined by regression analysis for each component of the minimum distribution system and by observing the change in costs with respect to the change in the respective number of customers. The marginal distribution demand cost is derived on an incremental basis by determining the increase in the distribution demand costs with respect to the increase in distribution demand.

The staff's approach to determining customer-related distribution costs differs from Edison's in two ways. First, Edison has ascribed two types of components to the minimum distribution system. One type of component is of a general nature and not identifiable by customer group. The other type of component is exclusive to and identifiable by customer group. Both types of components increase with the number of customers, but the magnitude of the change in total costs is different for each component. Edison regards this point as a crucial consideration in the correct determination of marginal costs. As an example, Edison points to the metering costs associated with time-of-use customers. It is Edison's position that, unless these components are identified correctly, other customer groups will be forced to bear their costs.

The staff, on the other hand, believes that Edison's approach is wrong and that it is tantamount to hypothesizing a distinct minimum distribution system for each class of customer. To demonstrate its position, the staff uses the example of the "minimum" large power customer. Under the Edison approach a minimum large power customer has a much greater transformer cost than its domestic counterpart. The staff believes that this confuses customer-related and demand-related costs, that is to say, large power customers are served by larger transformers simply because they have higher demands. The staff position is that the customer-related disbribution costs are essentially equal among customer groups.

The second difference in approach is that Edison trended both the number of minimum-system components and their respective costs for the years 1973 through 1977 to obtain 1981 unit costs. Because it did not regard the cost trends as reliable, the staff substituted recorded 1979 unit costs escalated to the 1981 level.

Another difference between Edison and the staff relates to the use of time periods in developing distribution demand costs. Edison has derived distribution demand costs according to costing periods. The staff, however, believes there is insufficient underlying data to make the necessary distinctions and has assumed equal cost causation for all time periods.

The system distribution demand does not vary in direct relation to the system generation demand. The distribution demand costs reflect the distribution plant investments only. The allocation factors for the generation level are therefore unsuitable for the allocation of distribution demand costs by time period alone. Edison derived allocation factors for distribution demand costs by time periods by analyzing sample data from a distribution substation and hourly load research data by customer groups.

In connection with the development of distribution demand costs, the staff recommends that Edison prepare a distribution-transformer load study prior to the next general rate case to better measure distribution-system cost causation. We concur in this staff recommendation.

D. APPLICATION OF MARGINAL COSTS

1. Development of Revenues

Table VI-A presents the staff's and Edison's estimated revenues from rates equaling the full marginal cost and their respective proposed cost recoveries by group. The staff estimate of revenues from full marginal cost rates is developed in a different manner from that of Edison. Edison's approach applies time-differentiated demand and energy usage. The staff approach develops estimated revenues by applying marginal costs to the estimated billing factors forecast for the actual meters to be used by customers in each customer group in test year 1981. In other words, the staff approach uses the billing factors for the actual meters rather than hypothesizing that each customer has a time-of-use meter. The actual-meter approach expresses demand costs in cents per kWh by using group load factors for customers without demand meters.

As can be seen from Table VI-A, there is very little difference between the estimates of the staff and Edison of revenues from rates at the full marginal cost. However, the application of Edison's time-differentiated demand and energy billing factors to staff's marginal costs would make the difference somewhat greater. The staff approach of using the actual-meter billing factors is preferred because revenues will be collected based on the use of the actual meters. Edison's approach of hypothesizing that all customers have time-of-use meters adds an element of potential error.

TABLE VI-A

REVENUE FROM FULL MARGINAL COSTS
AND PROPOSED COST RECOVERY BY GROUP

Customer Group	Average Number of Customers	Estimated Sales	Revenue From Full Marginal Costs		Proposed Cost Recovery	
			Staff	Utility	Staff	Utility
	(A)	(B) (MMkWh)	(C)	(D)	(E)	(F)
			(Dollars in Millions)			
Domestic	2,825,885	17,246.3	$2,101.0	$2,215.9	$1,335.2	$1,306.0
Lifeline	-	9,239.0	1,345.9	-	-	-
Nonlifeline	-	8,007.3	755.1	-	-	-
ighting & Small Power	316,788	11,862.5	1,206.9	1,117.0	932.9	957.6
Large Power	3,513	4,710.4	402.9	385.7	320.3	329.3
Time-of-Use	2,206	20,638.3	1,547.1	1,534.8	1,324.6	1,315.5
Agricultural and Pumping	32,926	1,833.9	190.3	201.9	138.0	140.2
Streetlighting	8,215	543.7	94.0	65.6	63.2	65.6
Total	3,189,533	56,835.1	$5,542.2	$5,520.9	$4,114.2	$4,114.2

The diversity or coincidence factor used to express demand costs in cents per kWh is a major element in the actual-meter approach. Edison is placed on notice that it should study the issue of diversity (coincidence) factors for use in its next general rate case. This should include providing additional detail on the revenue effects of each of several diversity factors and the advantages and disadvantages of using each, together with the diversity factors recommended for use in the actual-meter approach.

2. Cost Revovery By Customer Group

a. Recommendation of the Utilities Division

Using a revenue requirement based on Edison's proposed increase of $340.2 million, Table VI-B shows the development of cost recovery by customer group utilizing the method recommended by the Utilities Division of the staff. As can be seen from Table VI-A, the revenues from rates at full marginal cost would exceed the system's revenue requirement by some $1.4 billion. The problem thus becomes one of appropriately scaling this amount down by customer groups to equal in total the revenue requirement of the system while not distorting the resource use that would occur at full marginal cost level and providing an equitable assessment of the costs. The Utilities Division method achieves such a scaling down by assessing each customer group, as shown in Table VI-A, an equal percentage of the difference (EPD) between the revenues from full marginal cost and present revenues.

TABLE VI-B

UTILITIES DIVISION
COST RECOVERY BY
CUSTOMER GROUP

EQUAL PERCENT OF DIFFERENCE METHOD

Customer Group	Revenue from Marginal Costs	Present Revenue	Difference	Increase	% Incr.	Resulting Revenue	Resulting ¢/kWh
	(A)	(B)	(C)=(A)-(B)	(D)= (C) (340.2) / (1768.2)	(E)	(F)= (B)+(D)	(G)
			(Dollars in Millions)				
Domestic	$2,101.0	$1,152.7	$ 948.3	$182.5	15.8%	$1,335.2	7.74¢
Lighting and Small Power	1,206.9	867.6	339.3	65.3	7.5	932.9	7.86
Large Power	402.9	300.6	102.3	19.7	6.6	320.3	6.80
Time-of-Use	1,547.1	1,271.6	275.5	53.0	4.2	1,324.6	6.42
Agricultural and Pumping	190.3	125.6	64.7	12.4	9.9	138.0	7.52
Streetlighting	94.0	55.9	38.1	7.3	13.1	63.2	11.62
Total	$5,542.2	$3,774.0	$1,768.2	$340.2	9.0%	$4,114.2	7.24¢

The staff also furnished two alternative proposals based on variations of the EPD method. Table VI-C indicates the differences in cost recovery among customer groups if, as in the first alternative, customer-related costs are removed from total marginal costs, and if, as in the second alternative, both customer-related costs and demand distribution costs are removed. The staff thought underlying these alternatives is that any deviations from marginal costs would be in rates which have the least impact on demand and thus on the utility's resources. In other words, customer costs primarily affect the decision to connect or disconnect, not the level of use; and distribution costs are less sensitive to changes in demand than generation, or transmission costs, or energy costs which are directly a function of changes in demand. According to the staff, the exclusion of marginal customer and distribution costs would be expected to have less impact on Edison's resource response than exclusion of energy, generation or transmission costs, while bringing the revenues from marginal cost closer to the allowed revenues.

TABLE VI-C

COST RECOVERY BY VARIATIONS
OF THE EQUAL PERCENT OF DIFFERENCE METHOD

Group	All Costs (Proposed)		Without Customer-Demand Costs		Without Customer-Related and Demand Distribution Costs	
	Dollars	Percent	Dollars	Percent	Dollars	Percent
	(A)	(B)	(C)	(D)	(E)	(F)
	(Dollars in Millions)					
Domestic	$182.5	15.8%	$134.5	11.7%	$134.4	11.7%
Lighting and Small Power	65.3	7.5	81.2	9.4	75.7	8.7
Large Power	19.7	6.6	28.6	9.5	28.5	9.5
Time-of-Use	53.0	4.2	76.7	6.0	82.4	6.5
Agricultural and Pumping	12.4	9.9	15.8	12.6	15.6	12.4
Streetlighting	7.3	13.1	3.4	6.0	3.6	6.5
Total	$340.2	9.0%	$340.2	9.0%	$340.2	9.0%

b. Recommendation of the Policy and Program Development Unit

The witness for the staff's Policy and Program Development Unit recommended that rates be designed utilizing cost recovery by customer group on a marginal unit cost basis eliminating customer and distribution demand costs. Table VI-D shows the development of this proposed method of recovery as it was presented by the Unit in its late-filed Exhibit 75. The marginal cost data used in the preparation of this exhibit were taken from staff Exhibit 46, which the Unit's witness characterized as the "most reasonable marginal cost for use in this proceeding." He recommends that rates should not be authorized which exceed the average rates per kWh shown in Column G of Table VI-D.

Exhibits 46 and 75 provide the development of the following information with regard to the development of the average rates in Column G:

> ". . . The nonlifeline rate is set at the domestic group's marginal cost, with the lifeline rate at two-thirds of the nonlifeline rate. The increase to the agricultural and pumping group is restricted to 18%. Without restriction the result would be over 20%. A maximum of twice the overall requested increase of 9% is applied .... (The table) displays the results of assigning the same increase to street lighting as the smallest increase to any other group, i.e., 1.9%, assuming no group is to avoid some increase . . . . Given these specifications the percent of marginal cost for the other groups is derived which yields total revenues of $4,114,200,000. This is calculated at 95.9% of their marginal costs."

TABLE VI-D

DEVELOPMENT OF COST RECOVERY BY
CUSTOMER GROUP
(As Proposed by the Policy and
Program Development Unit)

Group	Revenue from Marginal Costs (A)	Present Revenue (B)	Marginal Cost (¢/kWh) (C)	Increase (D)	Percent Increase (E) = (D)/(B)	Resulting Revenue (F) = (B) = (D)	Resulting ¢/kWh (G)
			(Dollars in Millions)				
Domestic	$1,254.7	$1,152.7	-	$102.0	8.8%	$1,254.7	7.28¢
Lifeline	546.9	536.9	-	10.0	1.9	546.9	5.92
Nonlifeline	707.8	615.8	8.84¢	92.0	14.9	707.8	8.84
Lighting and Small Power	975.1	867.6	8.22	67.4	7.8	935.0	7.88
Large Power	360.8	300.6	7.66	45.4	15.1	346.0	7.35
Time-of-Use	1,432.3	1,271.6	6.94	101.7	8.0	1,373.3	6.65
Agricultural and Pumping	169.3	125.6	9.23	22.6	18.0	148.2	10.48
Streetlighting	55.9	55.9	10.28	1.1	1.9	57.0	10.48
Total	$4,248.1	$3,774.0	-	$340.2	9.0%	$4,114.2	7.24¢

With reference to Edison's rate proposal, the Unit's witness testified that Edison had neglected to take diversity appropriately into account. He pointed out an example where Edison's unit costs for the domestic and agricultural groups are less than the figures shown in Column G of Table VI-D. He said that this results from Edison's costs being based on diversified time peaks which show greater diversity between summer and winter peaks than is provided by the domestic and agricultural customers. He stated the staff development, which is based on actually metered energy levels and estimated group load factors, reflects the diversified summer peak demand of each customer group, whereas Edison's development is based on estimated diversified demand of each customer group during the six time periods.

c. Edison's Recommendations

Columns D and F of Table VI-A show, respectively, revenues by customer group based on recovery of full marginal costs as developed by Edison and revenues at the rates proposed by Edison in the application. The full marginal cost revenue was determined through the application of Edison's unit marginal costs to billing determinants for each customer group. Edison states that these determinants were developed assuming each customer would be billed on a time-of-use basis similar to that used for the development of marginal costs. The figures in Column D of Table VI-A represent the marginal costs to each customer's estimated equivalent billing determinants on a time-of-use basis. Edison then designed what it describes as "example marginal rates" to recover the marginal costs.

Edison's recommendations respecting marginal cost rates are clearly stated in the response of its witness to the following question by staff counsel:

> "Q. Would you recommend that these example rates be adopted in this proceeding."
>
> "A. Well, first of course, it should be recognized that these rates would produce approximately $1.4 billion of revenue in excess of the rates proposed in the application. Secondly, since the rates are somewhat over-simplified, no attempt has been made to develop a compatibility between rate schedules which are optional to the customer. As indicated in my earlier testimony, it is always necessary to develop compatible transition points between rate schedules sush as GS-2 and A-7. Finally, it should be recognized that the pure application of these rates would have the greatest impact on the domestic customer. The rates proposed in the application would produce in excess of 85% of marginal revenues for 3 customer groups (lighting and small power, large power, and TOU), but would produce only 59% of marginal revenues for the domestic customer group. Therefore, I would not recommend that the Commission adopt these rates in this proceeding."

Staff Exhibit 46 summarizes the staff analysis of Edison's recommendations on rate design, as follows:

> "Edison's proposal is based on setting the domestic and street lighting group revenues to return 8% at zero base fuel. The agricultural and pumping group is set at a proposed overall rate of 11.252% return on zero base fuel. Lighting and small power, large power and time-of-use group revenues are set at 85% of their revenues at full marginal cost.

"Edison's proposal is rejected since its foundation is a target rate of return for domestic, street lighting and agricultural and pumping groups (about 35.4% of present total revenues). Embedded costs and rates of return are not relevant for setting rates to maximize conservation and efficiency. While setting revenue targets for lighting and small power, large power and time-of-use at 85% of their marginal cost is an application of marginal cost and one may argue is more conservation and efficiency oriented, this approach is rejected for two reasons. First, it is partly a residual by first considering domestic, streetlighting and agricultural and pumping. As a residual it deviates from the conservation goal. Second, it is a straight application of equal percent of marginal cost. The equal percent of marginal cost approach is rejected in favor of the EPD method."

d. Adopted Cost Recovery by Customer Group

We reject Edison's proposal that embedded cost allocation be a significant basis for allocation of adopted cost recovery by customer group. Marginal cost as determined by the staff studies is the more suitable cost indicator and will be the principal basis for adopted cost recovery by customer groups. Of the alternatives presented by the staff, we reject the equal percent of difference method where all costs are included (Table VI-B) and no consideration is given to the State's lifeline rate program.

We find merit in the alternatives presented by the Utilities Division staff where customer-related and demand distribution costs are excluded (Table VI-C). Marginal customer and distribution demand costs are clearly related to the connection of new customers and will not be given significant weight in our marginal cost-based rates which are effective for both existing and new customers.

Changes in rate design should reflect an application of marginal cost principles to those sectors of utility operation which are significantly affected by customers' decisions to limit or increase energy conservation. To the extent the utility's revenue requirement can be met by assessing rates no higher than marginal generation and transmission costs, no customer class will be penalized and appropriate price signals will be provided to encourage conservation. The emphasis on marginal generation and transmission costs is fully consistent with marginal cost principles in effect in our design of natural gas rates where alternative fuel costs and marginal purchased gas cost play an important part. Consistency in our energy rate design programs will also provide proper price signals to customers deciding on forms of energy utilization.

We also find merit in the alternative presented by the staff witness for the Policy and Planning Division (Table VI-D) which reflects a specific adjustment for the State's lifeline rate program and is based on inclusion of only marginal energy and generation and transmission demand costs. The staff's further analysis of the benefits of the diversity of the agricultural class (Exhibit 50) also merits consideration in the adopted cost recovery.

Based principally on these marginal cost considerations, the base rate increases by the major customer groups will be as follows, with the total average rates and percentage increases therein shown for comparison.

	Base Rate Increase ($ million)	Total Average Rate	
		% Increase	¢ kWh
Domestic	93.5	9.3	6.68
Ltg. & Sm. Pwr.	67.8	8.7	7.46
Large Power	26.3	10.3	6.43
TOU	92.7	8.5	6.13
Ag. & Pump.	9.5	8.2	6.82
St. Ltg.	4.4	8.3	10.59
	294.2	8.9	6.67

The resulting rate relationship are found to be reasonable and will be maintained in subsequent ECAC proceedings by pursuing a policy of applying uniform increases or decreases on a ¢/kWh basis among customer groups until the rate structure is again reviewed in a general rate proceeding. Within the residential class, we will continue to evaluate the appropriate relationship between lifeline and nonlifeline rates in ECAC increases or decreases.

E. RATE DESIGN

1. General

Complete rate design presentations were made by Edison and the staff. In addition, the following parties participated in the portion of these proceedings related to rate design and revenue allocation to customers groups: California Energy Commission, California Manufacturers Association, California Industrial Energy Customers, California Retailers Association, California Farm Bureau Federation, California Community Colleges, Western Mobilehome Association, City of Long Beach, and the Christian Science Churches in southern California.

2. Edison's Proposed Rates

a. General

Table VI-E shows several significant effects for each of the customer groups under Edison's proposed rates.

TABLE VI-E

RATE OF RETURN EFFECTS OF EDISON'S PROPOSAL

Customer Group	Average Incr. ¢/kWh*	Total ¢/kWh*	% Increase	Proposed Rate of Return-%
Domestic	0.89	7.57	13.3	5.55
Lighting and Small Power	0.76	8.07	10.4	18.01
Large Power	0.61	6.99	9.6	13.15
Time-of-Use	0.21	6.37	3.5	16.50
Agricultural and Pumping	0.80	7.64	11.6	12.47
Streetlighting	1.78	12.06	17.3	8.01
Total	0.60	7.24	9.0	11.25

*Sum of the proposed base rates and the ECAC rates which were in effect at the time the application was filed (December 26, 1979).

b. Domestic Service

Edison's proposal would increase the monthly customer charges for domestic lifeline service from $2.00 to $3.75 and for domestic nonlifeline service from $4.50 to $5.00. In support of these proposed increases in customer charges, Edison points out that in each case they are at a level far below the level of marginal customer costs associated with such service. Edison in its study estimated the marginal customer cost to be $10.00 per month, and the staff in its study estimated the marginal customer cost to be $14.00 per month.

Edison proposes to consolidate the existing two-block lifeline energy rates into a single block, thus eliminating the present declining-block rate structure in the lifeline part of the domestic rates. Edison would maintain its present inverted domestic service energy rate, which has been a result of the lifeline allowances. Lifeline base rates for Edison's domestic customers have not been increased since January 1, 1976, and the 25 percent differential of Public Utilities Code Section 739(c) has been exceeded. Edison proposes, therefore, that the lifeline energy rates be increased by 27.3 percent.

Edison believes that its proposed domestic customer charges are more reasonable than the staff's proposal of freezing the present customer charges. Edison states that the combined effect of the customer charge and the energy charge proposals "enables the staff to propose a domestic rate design with much greater 'inversion' characteristic which, while on its face appearing to have greater conservation effectiveness, increases the potential for revenue and earnings instability markedly." Edison asserts that this instability could "have very serious implications for Edison and its shareholders alike and could result in further disenchantment on the part of the investment community which has for a number of years discounted Edison's stock below book value, thus adding significantly to Edison's problem of raising new capital to finance its huge ongoing construction program to meet increased demands for service."

c. General Service

For Lighting and Small Power Schedule No. GS-1, Edison proposes that the monthly customer charge be increased from $4.50 to $5.00, the same customer-charge proposal as for nonlifeline domestic service customers. The base-rate energy charge would be increased from 3.68¢ to 4.62¢.

For Lighting and Small Power Schedule No. GS-2, Edison proposes that the present demand charge of $76.00 for the first 20 kW or less of billing demand be increased to $102.00 and that demand in excess of 20 kW be increased from $3.80 per kW to $5.10. (This would continue the flat-rate form of the present demand rates.) For the energy charge, Edison would do away with the present sliding rate scale, which declines at base rates from 0.94¢ per kWh to 0.54¢. Instead, it would establish a base-rate charge of 1.03¢ for all energy used under this schedule.

General Service Schedule No. A-7, which is not applicable to demands between 200 kW and 1,000 kW, would be limited to demands between 200 kW and 500 kW because Edison now proposes to serve all customers with demands of 500 kW and up on time-of-use schedules. Edison proposes to increase the demand charge from $860.00 per month for the first 200 kW or less to $1,120.00 and to increase the charge for excess demand from $4.30 per kW to $5.60. The present three-block base rate for energy, which declines with use from 0.73¢ per kWh to 0.33¢, would be replaced by a single-block base rate of 0.83¢ per kWh.

Edison justifies its proposal to increase the customer charges for Schedule No. GS-1 and the demand charges for Schedules Nos. GS-2 and A-7 on the grounds that the present charge for each is substantially below marginal cost.

d. Time-of-Use Rates

Under Schedule No. TOU-8, Edison has proposed the extension of mandatory time-of-use rates to customers with demands in excess of 500 kW as compared to the present 1,000 kW. As shown in Table VI-G, Edison's proposal would reduce the customer charge from the present \$1,075.00 per month to \$560.00 and recover the shifted revenue requirement through increasing the demand charges by small amounts to \$5.60 per kW on-peak and to \$0.70 per kW mid-peak and by increasing the base-rate energy charges by 0.09¢ per kWh to 0.62¢ per kWh on-peak, 0.47¢ per kWh mid-peak, and 0.32¢ per kWh off-peak.

Edison proposes to retain the present structures of the six TOU-GSX and the eight TOU-D experimental rate schedules at generally greater customer, demand, and energy charges. This would retain the relationships between certain time-varying components and charges. In this manner, destruction of the experimental validity of these schedules should be avoided.

e. Agricultural and Pumping

Schedule No. PA-1 is applicable to power service for general agricultural and pumping purposes on a connected-load basis. Edison's proposal calls for the establishment of a \$5.00 per meter per month customer charge, and for increasing the connected-load service charge from \$11.95 per horsepower (hp) per year to \$2.00 per hp per month, and also for generally increasing energy charges and changing them from an annual to a monthly consumption basis.

Schedule No. PA-2 is applicable to power service for general agricultural and pumping service on a demand basis. Edison's proposal would increase demand charges from \$281.25 per month for the first 75 kW or less of billing demand to $382.50, and from $3.75 per kW per month for all excess demands to $5.10. A single base-rate energy charge of 0.83¢ per kWh would replace the present three-block energy charge, which declines with use from 0.76¢ per kWh to 0.36¢ per kWh.

Edison justifies increasing the demand charges in Schedules Nos. PA-1 and PA-2 on the basis that present charges do not recover costs. For example, Edison's figures show that the present Schedule No. PA-1 annual service charge of $11.95 per connected hp compares with its cost of over $40 per connected hp per year. In its opening brief, Edison states its position on agricultural and pumping rates thus:

> ". . . The reluctance of Staff to increase the demand and customer cost-related charges in Schedule PA-1 and PA-2, in spite of the fact that the present rates and even the rate increases proposed by Edison in customer and demand-related charges are well below the related costs, results in a disproportionately heavy burden of those costs being borne by those customers who, as a result of largely fortuitous circumstances of weather (cold temperatures requiring wind machine use and drought conditions requiring water pumping), have to use their wind machines and pumps.
>
> "Thus customers who have to use their equipment not only have to pay the high energy costs involved in such use under the ECAC rate but they, in effect, subsidize the cost of the standby service for those fellow agricultural and pumping customers who may be fortunate, as the result of the vagaries of weather, not to have to run their equipment as much or, perhaps, not at all. Furthermore staff's allocation of less total revenue requirement to the agricultural and pumping customer group (than Edison proposes)

> results in a degree of subsidization by other customer groups since Edison's proposed allocation would produce the rate of return for this group essentially equal to the overall return requested. There would seem little justification for not requiring this customer group to bear its full fair share of the cost of service, including a return commensurate with the cost of capital."

f. Streetlighting

Schedules Nos. LS-1 and LS-2 are applicable to streetlighting, LS-1 applying to utility-owned lighting facilities and LS-2 applying to customer-owned installations. Edison's proposed rates would increase average equivalent total energy charges by approximately 17 percent to yield a rate of return of eight percent on sales to this group. This is substantially below the proposed system rate of return. Edison relates that service to this group has traditionally been recognized to have special public interest aspects and that this has justified rates which may be considered to be subsidized in terms of not producing a rate of return commensurate with the cost of capital. Edison believes that its rate proposal maintains the traditional relationship between the rate of return for this group and the system average.

3. Staff Rate Proposals

a. General

For some service schedules, the Utilities Division of the staff in its Exhibit 46 presented three separate rate designs, which are designated as Alternative I, Alternative II, and Alternative III. In preparing these rate designs the staff used Edison's requested revenue increase of $340.2 million in all of them. It should be noted, however, that the revenues by customer groups which would be produced by the Exhibit 51 rate design are not necessarily the same as those which would be produced by the rate design alternatives in Exhibit 46. In Exhibit 46, the staff used Edison's proposed revenue increases by customer groups and rate schedules. Exhibit 51 on the other hand, is based on the staff marginal cost allocated to customer groups by the EPD method.

In addition to the rate designs presented by the Utilities Division in Exhibits 46 and 51, two other staff rate designs were presented, one by a witness representing the Policy and Program Development Unit and the other by an economist from the Electric Branch.

At the outset of this discussion regarding staff rate recommendations, we will discard the rate design of the economist because it is impractical. All of his recommended rates would equal full marginal costs; no other factor was considered in their design. The full marginal cost rates would extract from the public an overcollection of about $120 million per month above the revenue requirement of the system. Under this full marginal cost rate proposal each customer, after paying his bill, would receive a refund check representing his share of the $120 million per month over-collection. According to the proponent witness, the size of the monthly bill would convey to the individual customer precisely the right signals regarding his consumption, thus promoting conservation, efficiency, and equity. This rate design proposal would obviously not be acceptable to the public. Further, the marginal costs developed for this proceeding lack sufficient stability and accuracy to provide the sole basis for an adopted rate design.

Following discussion of the several Utilities Division recommendations, we will describe the rate design proposed by the Policy and Program Development Unit at the end of this section on staff-recommended rate design.

Table VI-F develops for comparative purposes the rates of return by customer group that would be produced by the staff rate design proposals in the staff's Exhibit 46.

TABLE VI-F

RETURN BY CUSTOMER GROUP
Utilities Division Rate Proposals

Customer Group	Present Total Revenue ($000)	Present Rate of Return (%)	Proposed Increase ($000)	Proposed Rate of Return (%)
Domestic	$1,152,662	1.89	$182,500	6.3
Lighting and Small Power	867,633	13.21	65,300	16.7
Large Power	300,592	9.14	19,700	11.7
Time-of-Use	1,271,598	14.29	53,000	16.9
Agricultural and Pumping	125,612	7.69	12,400	11.6
Streetlighting	55,909	4.66	7,300	7.1
Total	3,774,006	7.62	340,200	11.5

b. Domestic Service

As shown in Table VI-G, the staff proposes that the customer charges for both lifeline and nonlifeline domestic customers be held at their present level of $2.00 and $4.50, respectively. The staff recommends maintenance of the present customer charges in order to minimize the impact of any rate increase on low consumption customers.

The staff believes that Edison's proposal to increase lifeline energy charges by 27.3 percent is excessive and recommends an increase of no more than 15 percent. The staff states that its domestic rate recommendations are designed to encourage conservation and that they are consistent with the rate design recently adopted for PG&E in Decision No. 91107, supra.

Table VI-H shows a comparison of typical bills for domestic service at the rates proposed by Edison and the Utilities Division. The rates used in the billing comparisons include energy cost adjustment billing factors (ECABF) of 2.943¢ per kWh for consumption within the lifeline allowance and 5.382¢ per kWh for consumption in excess of the lifeline allowance. Lifeline quantities of 240 kWh have been assumed in computing billings for less than 1,000 kWh and 490 kWh for billings of 1,000 kWh or greater.

TABLE VI-G

COMPARISON OF PRESENT AND PROPOSED
BASE RATES FOR DOMESTIC SERVICE

Item	Present Rates	Utility-Proposed Rates	Staff-Proposed Rates Alt.I	Alt.II	Alt.III	Exh.51
Customer Charge						
Lifeline	$2.00	$3.75	$2.00	$2.00	$2.00	$2.00
Nonlifeline	4.50	5.00	4.50	4.50	4.50	4.50
Energy Charge						
Lifeline						
1st 240 kWh/kWh	0.02423	0.02520	0.02650	0.02819	0.02550	0.02980
Excess	0.01593	0.02520	0.02650	0.02819	0.03100	0.02980
Nonlifeline						
1st 500 kWh/kWh	0.02423	0.03400	0.0400	0.03786	0.0350	0.03970
Excess	0.02423	0.03400	0.0400	0.03786	0.0410	0.03970

TABLE VI-H

COMPARISON [illegible]LLS FOR DOMESTIC SERVICE
AT PRESEN[illegible]D PROPOSED RATES

kWh	At Present Rates	At Utility-Proposed Rates	At Staff Proposed Rates Alt.I	Alt.II	Alt.III	Exh.51
0	$ 2.00	$ 3.75	$ 2.00	$ 2.00	$ 2.00	$ 2.00
100	7.37	9.21	7.59	7.76	7.49	7.92
250	15.66	17.74	16.36	16.74	16.07	17.15
500	35.17	39.69	39.82	39.67	38.28	40.53
750	54.68	61.65	63.27	62.59	60.48	63.91
1,000	66.02	75.31	77.25	76.99	75.65	78.72
1,500	105.05	119.22	124.16	122.83	123.06	125.48
2,000	144.07	163.13	171.07	168.67	170.48	172.24
3,000	222.12	250.95	264.89	260.35	265.31	265.76

c. Multifamily Domestic Service

Customers on Schedule No. DMS-1 now receive a 10 percent discount. The staff believes that these customers would receive an adequate discount through the customer charge without the 10 percent discount. No objection was made to the staff proposal to eliminate this discount; therefore, the order herein will direct its elimination.

Service to master-metered mobile home parks is provided under Schedule No. DMS-2. Pursuant to the requirements of P.U. Code Section 739.5, a discount is now provided on all lifeline sales to compensate the mobile home park operators for the cost of the services which Edison would otherwise be obliged to provide to the tenants of the park. The staff recommends that the present 26 percent discount be reduced to 18 percent to reflect the 1981 estimated cost to Edison of providing comparable service to the submetered tenants, exclusive of installing and servicing the master meter. (The 18 percent recommendation is based on the rate design in Exhibit 51 and reflects a $4.78 cost per month to Edison; therefore, the recommended percentage would have to be changed for a different rate design.)

Schedule No. DM is entitled Domestic Multifamily Accommodation, Master Metered. Schedule No. DM provides additional lifeline allowances of 280 kWh for Zone H and 500 kWh for Zone V. The staff proposes to reduce these additional allowances to 225 kWh and 400 kWh, respectively, to make them consistent with the basic allowance. There was no opposition to this suggestion.

d. General Service

For Schedule No. GS-1, the staff proposes to keep the monthly service charge at its present level of $4.50. Table VI-I shows a comparison of utility-and staff-proposed rates for this schedule. Table VI-J shows typical monthly bills for various consumptions at staff-proposed rates. For these billing comparisons, the rates include an ECABF of 5.007¢ per kWh.

For Schedules Nos. GS-2 and A-7, the staff proposes to keep the present demand charges and to develop the necessary revenue for each schedule by increasing the energy rates. The staff supports Edison's proposal to change the existing three-block declining scale of energy rates into a single block.

The staff believes "that by increasing the energy rate, more conservation would be achieved and the conservation of energy may translate into conservation of capacity."

TABLE VI-I

COMPARISON OF PRESENT AND PROPOSED RATES
COMMERCIAL AND INDUSTRIAL SERVICE

Schedule No. GS-1

Item	Present	Utility-Proposed	Staff-Proposed Exh. 46	Staff-Proposed Exh. 51
Customer Charge	$4.50	$5.00	$4.50	$4.50
Energy Charge $/kWh	0.0368	0.0462	0.0469	0.0411

TABLE VI-J

TYPICAL MONTHLY ELECTRIC BILLS
COMMERCIAL AND INDUSTRIAL SERVICE

Schedule No. GS-1

kWh	At Present Rates	At Proposed Rates (Exh. 46)	Increase Amount	Increase Percent
375	$37.08	$40.86	$3.78	10.19%
750	69.65	77.23	7.58	10.88
1,500	134.81	149.96	15.15	11.24
3,000	265.11	295.41	30.30	11.43

Table VI-K shows a comparison of present and proposed rates for Schedule No. GS-2. Table VI-L presents comparisons of typical monthly bills at these rates for various consumption levels. The billing amounts include an ECABF of 5.007¢ per kWh.

TABLE VI-K

COMPARISON OF PRESENT AND PROPOSED RATES
COMMERCIAL AND INDUSTRIAL SERVICE

Schedule No. GS-2

Item	Present	Utility-Proposed	Staff-Proposed Exh. 46	Staff-Proposed Exh. 51
Demand Charge				
1st 200 kW or less	$76.00	$102.00	$76.00	$76.00
Excess kW/kW	3.80	5.10	3.80	3.80
Energy Charge				
1st 150 kWh/kW/kWh	0.0094	0.0103	0.0139	0.0140
Next 150 kWh/kW/kWh	0.0074	0.0103	0.0139	0.0140
Excess kWh/kWh	0.0054	0.0103	0.0139	0.0140

TABLE VI-L

TYPICAL MONTHLY ELECTRIC BILLS
COMMERCIAL AND INDUSTRIAL SERVICE

Schedule No. GS-2

kW	kWh	At Present Rates	At Proposed Rates (Exh. 46)	Increase Amount	Increase Percent
20	3,000	$ 254.41	$ 267.91	$ 13.50	5.31%
30	6,000	467.82	497.82	30.00	6.41
40	10,000	738.70	791.70	53.00	7.17
75	15,000	1,169.55	1,244.55	75.00	6.41
75	30,000	2,016.60	2,204.10	187.50	9.30
150	30,000	2,339.10	2,489.10	150.00	6.41
150	60,000	4,033.20	4,408.20	375.00	9.30

There are less than 2,500 customers receiving service under Schedule No. P-1, which is applicable to general service on a connected-load basis. This schedule has been closed to new customers since September 10, 1969. Edison recommends with the concurrence of the staff that the schedule be eliminated and that the present customers be transferred to Schedule No. GS-1. There was no opposition to this recommendation, and the order will eliminate Schedule No. P-1 from Edison's filed tariffs.

Table VI-M shows a comparison of utility-and staff-proposed rates for Schedule No. A-7.

TABLE VI-M

COMPARISON OF PRESENT AND PROPOSED RATES
GENERAL SERVICE SCHEDULE NO. A-7

Item	Present	Utility-Proposed	Staff-Proposed Exh. 46	Staff-Proposed Exh. 51
Demand Charge				
1st 200 kW or less	$860.00	$1,120.00	$860.00	$860.00
Excess kW/kW	4.30	5.60	4.30	4.30
Energy Charge				
1st 150 kWh/kWh	0.0073	0.0083	0.0118	0.0090
Next 150 kWh/kW/kWh	0.0053	0.0083	0.0118	0.0090
Excess kWh/kWh	0.0033	0.0083	0.0118	0.0090

e. Time-of-Use Rates

The staff states that, as a matter of policy, it supports the uniform and consistent application of time-of-use rates to customers with appropriate load characteristics. The staff believes that to exempt any group of such customers, or any individual customer, from the requirement to take service under a time-of-use tariff would constitute a preferential rate and would be contrary to Section 453 of the P.U. Code. The staff contends that, without a time-of-use rate incentive, exempted customers would be free to load the system indiscriminately during periods of peak demand, thus hastening, rather than postponing, the need for additional generating capacity.

The staff recommends that rates be increased to "meet revenue requirements for test year 1981 for TOU customers." It agrees with Edison's proposal to make Schedule No. TOU-8 mandatory for all general service customers with demands above 500 kW. It also agrees with Edison that any changes to the present experimental time-of-use rates should be made in a manner that would retain their experimental characteristics.

Table VI-N presents, for Schedule No. TOU-8, a comparison of present rates, Edison's proposal, and the three staff alternative proposals. Each of the four proposals is designed to yield for the test period approximately $43.7 million, or 14.3 percent, more revenue than present rates, based upon Edison's requested revenue increase.

For Alternatives I and II the staff would adopt Edison's proposed customer charge of $560.00, but it would maintain the present demand rates. The staff believes this to be a reasonable compromise between increasing all charges by 14 percent and eliminating demand and customer charges. The staff states that the energy charge of its Alternative III is based on marginal cost.

Energy rates for staff Alternative I, as in Edison's proposal, are designed to maintain the present 0.15¢ per kWh differential between time periods. Staff Alternative II uses Edison's proposed off-peak rate and equal rate differentials between periods. The resulting on-peak energy rate is 6.000¢ per kWh including ECAC. Reducing this by the voltage discounts developed for customers with demands below 1,000 kW, between 1.000 and 5,000 kW, and above 5,000 kW yields effective rates of 5.96¢, 5.85¢, and 5.73¢ per kWh, respectively. The staff states that these rates are close to the full on-peak marginal cost.

Staff Alternative III combines the $200.00 per month customer charge and the $5.30 per kW per month on-peak demand charge with the mid-peak demand energy charges of Alternative II to produce a marginal cost-based rate which would yield Edison's proposed level of Schedule No. TOU-8 revenue. The staff recommends the rate design of Alternative III for Schedule No. TOU-8.

The staff recommends that the present structure of Schedule No. TOU-8 as to the seasons and time period remain unchanged.

TABLE VI-N

COMPARISON OF PRESENT AND PROPOSED
TIME-OF-USE RATES

Schedule No. TOU-8

Item	Per Meter Per Month				
	Present	Edison Proposal	Staff Alt.I	Staff Alt.II	Staff Alt.III
Customer Charge	$1,075.00	$560.00	$560.00	560.00	$200.00
Demand Charge					
$/Maximum kW Demand In Each Time Interval					
On-Peak	5.05	5.60	5.05	5.05	5.30
Plus: Mid-Peak	0.65	0.70	0.65	0.65	0.65
Plus: Off-Peak	0.00	0.00	0.00	0.00	0.00
Energy Charge					
c/kWh In Each Time Interval					
On-Peak	0.530	0.620	0.740	0.993	0.993
Mid-Peak	0.380	0.470	0.590	0.656	0.656
Off-Peak	0.230	0.320	0.440	0.320	0.320
Base Revenue - $M	$306,026	$349,700	$349,688	$349,658	$350,350

The staff expresses the belief that, until there is definite evidence of the need to change the established rate structure, the problems of customer acceptance of and adaption to time-of-use rates should not be subjected to unnecessary complications.

Edison's time-of-use rate experiments are designed to maintain certain relationship between the time-varying components; hence, any changes must be made in a manner that will maintain these relationships. The staff has reviewed the six Experimental Schedules Nos. TOU-GSX (Time-of-Use Test - General Service) and the eight Experimental Schedules Nos. TOU-D (Time-of-Use Test - Domestic Service), and it concurs in the rates proposed by Edison for these schedules.

The staff also agrees with two agricultural time-of-use rate proposals made by Edison. One of these is a proposed special condition that offers a $1.00 per horsepower per month (or 50 percent reduction in the proposed $2.00 monthly service charge) to any PA-1 customers who forego use of their equipment from 8:00 a.m. to 10:00 p.m., Monday through Friday. Edison proposes that this present experimental special condition which is now available only to 500 customers be opened to all interested PA-1 customers. The other Edison proposal concerns Experimental Schedule No. TOU-PA-1 (Time-of-Use - Agricultural and Pumping) which is available on one-year contracts to 500 customers. That schedule now offers an on-peak to off-peak energy rate of 10.5 to 1 as an incentive to customers to consume energy during off-peak hours. Edison proposes to increase that ratio to 14.75 to 1.

f. Agricultural and Pumping

For Schedule No. PA-1, Edison is requesting authority to institute a customer charge, to alter the annual connected-load charge into a more expensive monthly charge, and to consolidate the present three energy blocks into two energy blocks. The staff, for its part, proposes that there be no customer charge, but would agree to a smaller monthly connected-load charge and to consolidating the energy charge into two blocks.

Table VI-O gives a comparison of the present Schedule No. PA-1 rates with the proposals of Edison and the staff.

TABLE VI-O

COMPARISON OF PRESENT AND PROPOSED RATES
AGRICULTURAL AND PUMPING POWER

Schedule No. PA-1

PRESENT RATES

Hp of Connected Load Per Meter	Service Charge Per Year Per Hp	Energy Charge $/kWh First 1,000 kWh/Hp	Next 1,000 kWh/Hp	Excess
2 and over	$11.95	0.0180	0.0117	0.0087

UTILITY PROPOSED RATES

Customer Charge Per Month	Hp of Connected Load	Service Charge Per Month Per/Hp	Energy Charge $/kWh First 200 kWh/Hp	Excess
$5.00	2 and over	$2.00	0.0164	0.0100

STAFF-PROPOSED ALTERNATIVE I

Customer Charge Per Month	Hp of Connected Load	Service Charge Per Month Per/Hp	Energy Charge $/kWh: First 200 kWh/Hp	Energy Charge $/kWh: Excess
None	2 and over	$1.00	0.02527	0.01887

STAFF-PROPOSED ALTERNATIVE II

Customer Charge Per Month	Hp of Connected Load	Service Charge Per Month Per Hp	Energy Charge $/kWh
None	2 and over	$1.25	0.0209

STAFF PROPOSAL (EXH. 51)

Customer Charge Per Month	Hp of Connected Load	Service Charge Per Month kWh/Hp	Energy Charge $/kWh: First 200 kWh/Hp	Energy Charge $/kWh: Excess
None	2 and over	$1.00	0.0235	0.0185

In its Alternative I for Schedule No. PA-2, the staff proposes to keep the demand rates at the present level. In Alternative II, the staff proposes to increase the demand rates in proportion to the total requested increase in the base revenue. The staff concurs with Edison's proposal to eliminate its declining block rate structure and to institute a single block.

Table VI-P shows a comparison of present Schedule No. PA-2 rates with the proposals of Edison and the staff.

TABLE VI-P

COMPARISON OF PRESENT AND PROPOSED RATES
AGRICULTURAL AND PUMPING POWER

Schedule No. PA-2

Item	Present	Utility Proposed	Staff Proposed Alt. I	Staff Proposed Alt.II	Staff Proposed Exh. 51
Demand Charge					
First 75 kW	$281.25	$382.50	$281.25	$348.75	$281.25
Excess kW/kW	3.75	5.10	3.75	4.65	3.75
Energy Charge/kWh					
First 150 kWh/kW/kWh	0.0076	0.0083	0.0137	0.01077	0.01250
Next 150 kWh/kW/kWh	0.0056	0.0083	0.0137	0.01077	0.01250
Excess kWh/kWh	0.0036	0.0083	0.0137	0.01077	0.01250

g. Rate Design of the Policy
<u>and Program Development Unit</u>

Table VI-Q compares the rates of return which would be produced by the rate design based on the application of marginal costs in the manner recommended by the staff's Policy and Program Development Unit.

TABLE VI-Q

RETURN BY CUSTOMER GROUP
(Policy and Program Development Unit)

Customer Group	Present Total Revenue ($000)	Present Rate of Return (%)	Proposed Increase ($000)	Proposed Rate of Return (%)
Domestic	$1,152,662	1.89	$102,000	4.3
Lighting and Small Power	867,633	13.21	67,400	16.8
Large Power	300,592	9.14	45,400	15.4
Time-of-Use	1,271,598	14.29	101,700	19.4
Agricultural and Pumping	125,612	7.69	22,600	15.2
Streetlighting	55,909	4.66	1,100	5.0
Total	$3,774,006	7.62	$340,200	11.25

Table VI-R shows illustrative rate structures presented by the Policy and Program Development Unit. These are based on the marginal cost development of Table VI-D.

TABLE VI-R

ILLUSTRATIVE RATE STRUCTURES
(Policy and Program Development Unit)

LIGHTING & SMALL POWER

Schedule No. GS-1

Customer Charge		
Per meter/month		$4.50
Energy Charge		
First 20 kWh/kWh		0.0368
Excess/kWh		0.0376

Schedule No. GS-2

Demand Charge		
First 20 kW		$76.00
Excess kW/kW		3.80
Energy Charge		
First 1600 kWh/kWh		0.0094
Excess/kWh		0.0173

AGRICULTURAL & PUMPING

Schedule No. PA-1

Service Charge		
Per Year per Hp		$11.95
Energy Charge	TOU Option	Standard
On Peak per kWh	0.034	0.026
Mid Peak per kWh	0.016	0.026
Off Peak per kWh	0.011	0.026

4. Positions of Interested Parties On Rate Design

a. California Energy Commission (CEC)

Because it is a fixed monthly charge which does not fluctuate with changes in energy consumption, the CEC believes that the customer charge has the regressive effect of reducing the benefit to a customer who takes vigorous measures to conserve energy. CEC contends that this results in the smaller or more conservation-minded consumer subsidizing the larger or more profligate consumer and that, further, he receives a misleading signal about the value of his conservation efforts.

CEC urges us to eliminate customer charges and to allow utilities to recoup the difference in revenue through a higher energy charge. CEC asserts that this shift would be consistent with the principles of marginal cost pricing and would have two salutary effects: (1) it would result in a more equitable pricing policy because customers would be charged more directly in accordance with the costs they impose on the system; and (2) it would enhance the cost-effectiveness of conservation measures and thereby provide customers with a more accurate signal of the economic value of conserving.

CEC asserts that eliminating or reducing the customer charge is one of the more obvious steps that Edison could have proposed to comply with the directive of Decision No. 89711, supra. CEC urges the Commission, consistent with the spirit of that decision, to compel Edison to eliminate all customer charges and to recoup the resulting revenue deficiencies by a higher energy charge.

Edison has proposed in this application to increase both the time-differentiated demand charges in Schedule No. TOU-8 and the non-time-differentiated demand charges in Schedules Nos. GS-2 and A-7. CEC believes that these proposed increases in the demand charge are inequitable, are at variance with the Commission's marginal cost pricing policy, and are unlikely to reduce effectively either peak demand or overall energy use. CEC urges that, instead, the demand charges in Schedule No. TOU-8 be eliminated in this rate case, and that the resulting loss in revenue be recouped through higher on-peak and mid-peak energy charges. Additionally, CEC proposes that the Commission require Edison to begin the installation of time-of-use meters for all customers now on Schedules Nos. GS-2 and A-7 and require Edison to implement time-of-use metering for these schedules in its next general rate case.

CEC argues that the demand charges Edison now seeks to increase are inequitable, fail to encourage conservation, and may actually increase system peak demand. It urges the Commission to eliminate such charges and to allow Edison to recoup revenue differences through increased time-of-use energy charges. Thus, CEC reasons, the inequity suffered by small consumers and cogenerators subject to demand charges would be replaced by a schedule which charges only for the amount of electricity used according to its value at time of use. CEC points out that the California electric system closest to implementing the rate design it is recommending, the Los Angeles Department of Water and Power, experienced a decrease in system peak demand during 1979-1980, the year in which it first shifted away from the demand-charge concept and toward time-of-use charges. CEC states that a similar shift by Edison is necessary if it is to comply with the Commission's directive in Decision No. 89711.

b. California Manufacturers Association (CMA)

CMA opposes the use of marginal costs as a sole or even primary determinant in the development of Edison's rates. CMA believes there are numerous theoretical and practical problems which would render such pricing of electricity not only unproductive of the goals sought by its advocates, but actually detrimental to attainment of those goals and to the Edison system generally. CMA contends that whatever price-signal benefits there may be in marginal costs can be obtained by the judicious application of marginal costs to rate design after revenue responsibility is determined on the basis of embedded costs.

Among the practical problems that CMA sees in this proceeding is the lack of meaningful and reasonably accurate estimates of marginal capacity costs in both Edison's and the staff's showings. CMA concedes that Edison's Scenario Methodology has definite advantages over other methods but notes that this method does not really measure the marginal cost of demand, but rather the cost of reductions in demand. CMA points out that the two are not necessarily related. CMA also points out that the staff assumption of combustion turbines, or "peakers", produces marginal demand generation costs which bear little resemblance to the optimal addition to Edison's capacity. CMA states that the peaker approach has been rejected by the MCPP task force as inappropriate.

CMA sees accuracy as a serious problem respecting marginal energy costs. In their respective showings, both Edison and the staff used recorded system-lambda information multiplied by a simple factor of two to represent marginal energy cost in the test year. CMA contends, and we have to agree, that the factor of two is simply the result of an educated guess as to the rise in the price of low-sulfur fuel oil over the two-year period, 1981-1982.

A second problem CMA sees respecting marginal energy cost is that both Edison and the staff have used system-lambda data estimated for the test year. The problem CMA discerns with their approaches is that, on the Edison system, the marginal unit does not create the highest energy cost because Edison's electric generating plants are dispatched to minimize impact on air quality rather than solely on the basis of cost. The result is that there is very little difference in the system-lambda between on-peak and off-peak periods. As calculated by the staff, in the summer the difference is 2.0 mills, and in the winter it is only 1.1 mills.

CMA asserts that each of the staff's rate proposals makes an improper allocation of marginal costs. CMA bases this assertion on the belief that the staff's EPD approach results in rates which bear little relation to marginal cost by customer groups. In support of this view, CMA offers the following rationale in its opening brief:

> "Under this equal percent of the difference (EDP) (sic) approach, revenues for each class are moved toward marginal cost by an equal percent of the present gap between class revenues and class marginal cost. This calculation results in total system revenues that equal the revenue requirement but fails to relate class revenues to marginal cost in any meaningful way. Only after 5 or 6 iterations (10 to 12 years) of this EPD approach would the various customer classes pay the same percentage of their respective marginal costs . . . For the test period these percentages would range from a low of 64% for the residential class to a high 87% for the TOU class . . . It is very difficult to see any justification in marginal cost theory or otherwise for the maintenance of these disparate percentages. If marginal costs are to form the basis for class revenue responsibility, this sort of hedging should not be tolerated."

Another problem CMA perceives in the staff's EPD approach is that it has used marginal cost revenues based on class diversity rather than on time of use. CMA states that the effect of this is that residential revenues are $31 million less than would be indicated if the staff used a consistent approach to the marginal cost development.

c. <u>California Industrial Energy Consumers (CIEC)</u>

For purposes of this proceeding 20 corporations, all of which own and operate manufacturing facilities within Edison's service area, have identified themselves as a group referred to as the California Industrial Energy Consumers (CIEC). The members of this group include: Airco, Inc.; Armco, Inc.; Ball Corporation; California Portland Cement Company; Champlin Petroleum Company; Crown Zellerbach Corporation; General Motors Corporation; Kaiser Cement Corporation; Kaiser Steel Corporation; Kimberly-Clark Corporation; Mobil Oil

Corporation; Monolith Portland Cement Company; Monsanto Company; PPG Industries, Inc.; Riverside Cement Company; Soule Steel Company; Southwestern Portland Cement Company; Stauffer Chemical Company; Texaco Incorporated; Thatcher Glass Manufacturing Company; and Union Carbide Corporation.

In its opening brief, CIEC offers the following statement of position:

> "It is the position of the companies on whose behalf this brief is offered that costs, actual costs, should be the bedplate and foundation on which the ratemaking process should rest. This is true with respect to the overall revenues to which the utility is permitted an opportunity to collect (i.e., the costs reasonably incurred in doing business) and with respect to the rates which are imposed on the customers (i.e., that each customer should pay rates which reflect the costs incurred in serving him). These parties believe that a fully allocated cost-of-service study provides the ratemaker with a breakdown of those costs which the utility must recover in order to maintain its financial integrity and, further, such a study provides the ratemaker with a regulatory 'sextant' so to speak, with which the regulator can determine the present positions of the class rates of return and the direction toward which they should be moved. Finally, it is noted, cost of service is listed as the very first of the standards enumerated in the Public Utility Regulatory Policies Act in Section 111, said act having, as its three major objectives, conservation, efficiency and equity. These parties believe that these objectives are best achieved, in total and without diminution of any one of them, by adherence to cost of service principles."

A witness for CIEC presented a recommended time-of-use rate design which he described as being based on the actual cost of service elements that pertain to Schedule No. TOU-8 customers, tempered with recognition of the fact that customers have made investments based on the existing rate structure. The rate design includes a customer charge of $625 per month, which is equal to the corresponding unit cost calculated by Edison. With respect to energy charges, the witness explained that Edison's current energy charges exceed energy costs. For purposes of maintaining continuity in the rate structure, however, he recommended leaving energy charges at their present level and deriving the balance of the required additional revenues by increasing the on-peak demand charge.

The recommendation of CIEC regarding the allocation of revenue responsibility between classes is shown in Table VI-S.

TABLE VI-S

REVENUES BY CUSTOMER GROUP
AS PROPOSED BY CIEC

Customer Group	Present Revenues ($000)	Present Rate of Return (%)	Recommended Increase ($000)	Proposed Rate of Return (%)
Domestic	$1,152,662	1.89	$210,325	6.91
Lighting & Small Power	867,633	13.21	42,695	15.49
Large Power	300,592	9.14	23,416	12.40
Time-of-Use	1,271,598	14.29	40,188	16.31
Agricultural & Pumping	125,612	7.69	11,021	11.30
Streetlighting	55,909	4.66	12,539	9.01
Total	$3,774,006	7.62	$340,184	11.25

CIEC characterizes the basis for this recommendation as:

> "...simply that the distribution of the proposed increase should represent a movement toward the recovery of costs so as to move class rates of return toward the system rate of return. [A witness for CIEC, in advancing the proposition] ...that equalizing all class rates of return with the system average (i.e., removing all subsidies) would represent unduly abrupt and perhaps disruptive changes, proposed instead that the percentage increase to any class be limited according to the following formula:
>
> > 'Each customer class should receive an increase equal to the average increase as a percentage of rate base, adjusted by 1/2 of the deviation of that classes' [sic] rate of return from system average rate of return at present rates.'"

CIEC offers the following reasons why it believes the revenue allocation shown in Table VI-S is superior to the proposals of other parties:

> "First, it is based on actual costs and the rate base numbers associated with each class. Moreover, it is tied into the actual revenue dollars being generated from each class. Thus, this approach deals with both aspects of electric service, i.e., costs and revenues. In addition, the classes are being moved at a known and measured progression towards a balance. Further, note the ease and simplicity with which the proper movements in rates of return are made to the customer classes. Finally, note the 'clustering of class rates of return around the system average which none of the other proposals can claim.'"

d. <u>California Retailers Association (CRA)</u>

CRA is a nonprofit organization comprising retail firms varying widely in size and type, including department, grocery, specialty, variety, drug, and furniture firms. CRA states that there are more than 150,000 firms engaged in the retail business in California.

CRA believes that marginal costs should be the principal determinant in setting rates. It proposes a revenue spread by customer groups which it states best reflects marginal costs. CRA proposes that, as nearly as practical, each group should pay an equal percentage of the marginal costs associated with service to that group, subject to the caveat that no group should receive a reduction.

Table VI-T shows revenues by customer group as proposed by the CRA witness.

TABLE VI-T

REVENUES BY CUSTOMER GROUP
AS PROPOSED BY CRA

Customer Group	Revenues at Rates Proposed by CRA ($MM)	Increase Over Present Rates ($MM)	Increase Over Existing Rates (%)	Percent of Marginal Cost Utility (%)	Percent of Marginal Cost Staff (%)	Return (%)
Domestic	$1,483.3	$330.6	28.7	66.9	70.6	9.78
Lighting and Small Power	867.6	-	-	77.6	71.9	13.21
Large Power	300.6	-	-	78.0	74.6	9.14
Time-of-Use	1,271.6	-	-	82.9	82.2	14.29
Agricultural and Pumping	135.2	9.6	7.6	67.0	71.0	10.84
Streetlighting	55.9	-	-	85.2	59.5	4.66
Total	$4,114.2	$340.2	9.0	74.5	74.2	11.25

CRA supports elimination of demand charges from time-of-use rates in order to better reflect system cost incurrence. Table VI-U shows CRA's rate proposal for Schedule No. TOU-8.

TABLE VI-U

SCHEDULE NO. TOU-8 RATES
PROPOSED BY CRA

	Charges Per Meter Per Month	
	Present	Proposed
CUSTOMER CHARGE	$1,075.00	$206.00
ENERGY CHARGE AT BASE RATES		
All on-peak kWh, per kWh	0.530¢	2.411¢
All mid-peak kWh, per kWh	0.380¢	1.729¢
All off-peak kWh, per kWh	0.230¢	1.046¢

CRA takes the position that the staff revenue spread proposals make improper use of marginal costs. According to CRA, the Utilities Division proposal is infirm because it does not go far enough in basing rates on marginal costs, and the Policy and Program Development Unit recommendation is suspect because it ignores relevant costs and provides an inappropriate advantage for domestic customers. CRA also contends that the Edison proposal is inconsistent with the Commission's ratemaking standards because it plainly does not rely on marginal costs in developing the allocation by customer group. CRA recommends against the adoption of inverted rates for commercial customers because such rates are unrelated to costs and because they discriminate, without any basis, against large customers in favor of small customers.

e. <u>California Farm Bureau Federation (Farm Bureau)</u>

Farm Bureau is a nonprofit, nongovernmental, voluntary association of farmers and others concerned with agriculture. With over 90,000 member families, it is the largest farming organization in the State. Its purpose is to advance the economic, social, and educational interests of its members.

Farm Bureau has participated actively in this proceeding. It has taken a position on a broad spectrum of issues; however, the main thrust of its participation relates to the design of agricultural schedules and to related matters which impact upon the rates paid by farmers. Farm Bureau asserts that Edison's proposals for the agricultural schedules are unacceptable to farmers. Our experience at the public hearings in this proceeding confirms this assertion. Edison's proposals were the cause of the attendance of hundreds of angry farmers who came in protest.

Farm Bureau is most concerned over Schedule No. PA-1, which applies to on-farm nondomestic use. It is greatly concerned, too, over Schedule No. PA-2, which also applies to on-farm and pumping use where there is a minimum demand of 75 kW.

Schedule No. PA-1 has two types of charges. One type is based on the horsepower of motors (or equivalent load) connected to Edison's system through any one meter. It is called an "annual service charge". The annual service charge is currently \$11.95 per hp. As Farm Bureau points out, this charge is collected even if the equipment is never turned on. The other type is the energy charge which is billed according to a declining three-block rate.

Edison proposes to add to Schedule No. PA-1 a customer charge of \$5.00 per month per meter and to increase the service charge to \$2.00 per hp per month, which is effectively \$24.00 per hp per year. Edison would collect the monthly service charge each month, eliminating the prepaid aspect of the current annual billing. Edison also proposes to reduce the number of energy blocks to two and to base them on monthly load factor rather than annual load factor.

Farm Bureau strongly objects to Edison's proposal to more than double the service charge. This charge is also known as connected-load charge and is widely referred to by farmers as the "stand-by charge". Farm Bureau asserts that the magnitude of the increase proposed by Edison in this charge is unwise and inappropriate for the following reasons:

1. Almost all of the additional charges to agricultural customers would be recovered through the new customer charge and the doubled service charge. Essentially none would be recovered through energy charges.

2. The proposed service charge would cause great damage and create financial havoc in a specific segment of agriculture, i.e., the citrus industry. Citrus growers depend on large motor-driven propellers to protect their crops from frost damage. The cost of electric wind machines is a very considerable part of the cost of growing a citrus crop.

3. An identifiable group of low-load-factor agricultural customers would receive a disproportionate increase under Edison's proposal, as much as 75 to 100 percent. This would not be in proportion to the proposed overall agricultural increase of 11.6 percent. It would also be disproportionate to increases that low-load-factor customers on other schedules would receive.

4. The Commission has stated that historical rate structure is one of its considerations in rate design. Farmers have invested heavily in electric wind machines over the years in the belief that rates would be structured to make their continuing use possible.

5. The proposed rates would drive farmers to other means of propulsion for their wind machines. They would install diesel and gas engines, which are inconvenient for the farmer and bad for air quality.

6. Edison's proposal would magnify already existing differences with PG&E's agricultural rates. PG&E Schedule No. PA-1 service charge is $0.60 per hp per month and was not increased in PG&E's last general rate proceeding. By comparison, Edison's current charge is effectively $1.00 per month and Edison proposes to double it to $2.00. The cost of having a wind machine standing idle in the field is $720 per year for PG&E customers, and it would become $2,400 per year for the Edison customer across the road. Farm Bureau points out that there is no explanation in the record as to why this should be allowed.

Farm Bureau's position on the several issues of primary concern to agriculture is summarized in its opening brief as follows:

"1. A rate of return on common equity at or somewhat above the staff recommendation of 13.60% is reasonable. 15.0% as requested by Edison is excessive.

"2. A step increase is the appropriate solution for attrition.

"3. If the Commission is guided by average or embedded costs, an increase to agriculture of slightly above $10,860,000 is justified (assuming a $340 million total increase).

"4. If the Commission relies on marginal costs, agriculture should receive a $9,600,000 increase (assuming a $340 million total increase).

"5. There should be no increase in the PA-1 service charges and no customer charge should be added. The time periods for the off-peak credit should be liberalized.

"6. A vigorous, voluntary time-of-use program for agriculture should be implemented with costs and revenue shift spread over all customers.

"7. Edison should make all efforts to consolidate billings."

f. California Community Colleges (Colleges)

Colleges are a statewide system of 106 community colleges, 16 of which would be affected by the rate increase requested by Edison. Colleges state that they have been classified as time-of-use consumers and are, therefore, particularly interested in the issue of rate design for Schedule No. TOU-8.

Colleges assert that the Commission's time-of-use rate policies have failed to shift demand to off-peak hours and have had devastating economic consequences on the consumer and his activities. Colleges offer themselves as an example of a consumer group which has been unduly burdened by an unjust and excessive rate design. Colleges contend that they have to pay more than their fair share of costs because of excessive subsidies which distort the real cost signals.

The community college system operates principally from September to June, between the hours of 7:00 a.m. and 11:00 p.m. Approximately 1.2 million students are enrolled in the community and junior colleges in California. A profile of the average enrollee reveals a part-time student who is 27 years old, who works during the day, and who attends classes afterward. The majority of the enrolled are part-time students who normally attend late afternoon and/or evening classes, which are unavoidably scheduled during the on-peak hours.

Colleges, because they serve the community, must schedule classes at a time that their students are able to attend. Necessarily then, in the Colleges' case, the facilities reach maximum use during the on-peak period. Thus, Colleges cannot continue to serve the community and its students and avoid the peak-hour rate. They have no flexibility in shifting their electricity demands to off-peak hours.

The nature of the services and the programs they provide to their communities forbids any shifting of schedules. As Colleges point out, in their instance, it is the clientele (the students) and the product (an evening education), not the rate design, which are controlling in determining how much energy is used and when.

Colleges summarize their position in this proceeding as follows:

> "Colleges oppose any form of time-of-use (TOU) rate, specifically the winter on-peak hour rate, that is set arbitrarily so as to force large use customers to shift their consumption off an on-peak period thereby escaping the excessively high on-peak rates. As presently implemented, the TOU rate is excessive, unfair, and goes beyond burdening to penalizing consumers like Colleges who, due to their activities, cannot shift their operations off an on-peak period. Thus, they are forced to pay excessive rates which place a devastating and undue hardship on them. Colleges oppose the excessive TOU rate of $5.05 per kW and oppose any proposal to increase that rate.
>
> "In the event that the time-of-use rate is retained for the Colleges, and other similarly situated consumers who are forced to pay the higher on-peak hour rate because they cannot switch their operation to another time period, Colleges support a shortened on-peak period. The current on-peak winter hours in which the TOU-8 rate is in effect is 5 p.m. to 10 p.m. Colleges propose a modification of the range to 6 p.m. to 9 p.m.
>
> "Should the time-of-use rates be retained, Colleges take the position that pricing policies are sound, reasonable and fair elements of a rate structure only if they are based on the actual cost of service incurred by the utility in providing electricity to that consumer. Colleges oppose a rate structure based on marginal costs, which are unknown future costs, as proposed by the staff.

"Finally, Colleges support Edison's proposal to extend the TOU-8 rate to customers with on-peak demands greater than 500 kW/month. However, Colleges take the position that minimum use levels should be totally eliminated. In other words, Colleges believe that all customers should pay their fair share for the electricity they use, at the time they use it. Large-use customers should not, as they do now, subsidize the on-peak use of electricity by domestic and other customers who use less electricity, but use it to a much greater degree during on-peak hours."

g. Western Mobilehome Association (WMA)

WMA is an association of mobile home park operators. WMA addresses itself in this proceeding to the issue of the rates which should be charged mobile home park operators who provide electric service to their tenants through submeters after purchasing the electricity from Edison through master meters.

WMA's position in this matter may be summarized as follows:

1. The cost to the utility to provide comparable services beyond the master meter is the controlling cost in this case, pursuant to P.U. Code Section 739.5.

2. The language "comparable services beyond the master meter" does not permit a deduction of costs not incurred. WMA is here contesting the deduction by the staff of "phantom" costs for a master meter transformer.

3. The cost incurred by the mobile home park operators in Edison's territory to provide their tenants with service has increased. WMA's expert witness testified that the annual costs employed in 1977 should be increased from $4.88 to $5.85 to reflect 1981 costs.

4. If the Commission does not adopt Edison's proposal to increase the customer charge from $2.00 to $3.75, the present discount of 26 percent is inadequate. WMA contends that the 26 percent discount cannot be decreased without doing violence to the statute, and that, if the Commission correctly computes the cost of providing comparable service, the discount should be increased to 30 percent.

5. WMA cannot support a rate design proposal based on zero customer charge unless the percentage discount on lifeline blocks is increased substantially beyond 30 percent.

Regarding WMA's position, Edison asserts there is no support in the record that the utility's cost of service is controlling because it is lower than the cost to the park. Further, Edison does not agree that the master meter cost should not be included as a deduction in determining Edison's total costs. Edison has proposed that the discount be reduced to 15 percent concurrent with the customer charge being increased to $3.75. If the customer charge is not increased, as proposed by the staff, then Edison states the discount should remain at 26 percent.

h. City of Long Beach (Long Beach)

The primary issue in this proceeding concerning streetlighting service relates to whether or not Edison should be required to offer low-pressure sodium-vapor lamps under its Schedule No. LS-1, which is applicable where Edison owns and maintains the streetlighting equipment. Low-pressure sodium-vapor lamps are now permitted under Schedule No. LS-2, which is applicable where the customer owns the streetlighting equipment, although a specific provision for such service is not now spelled out in that schedule.

Long Beach recommends that the Commission order Edison to offer streetlighting service with low-pressure sodium-vapor lamps under Schedule No. LS-1. Long Beach has converted all of its more than 24,000 city-owned streetlights to the low-pressure sodium-vapor type, which, it contends, are more energy efficient than the high-pressure lamps and thus promotes conservation. The staff concurs with this recommendation.

Long Beach believes that low-pressure sodium-vapor lamps should be offered on Schedule No. LS-1 at a rate at least as favorable as that for high-pressure lamps. Under Edison's proposal for Schedule No. LS-2, the rate for its city-owned low-pressure sodium-vapor lamps would be increased 45 percent for all-night multiple lamps and 57 percent for all-night series lamps. By way of comparison, Long Beach points out that under Schedule No. LS-1 the rate for low-pressure lamps on the Edison-owned lighting system would be increased on an average by only 22 percent.

Long Beach argues that, while authorities may differ on the relative merits of low-pressure and high-pressure sodium-vapor lamps, if a community has, for reasons of its own, selected the low-pressure type, then specific provisions for it should be included in Schedule

No. LS-2.[12/] In Addition, Long Beach requests that a specific rate be established for low-pressure sodium-vapor lamps in Schedule No. LS-2. The staff does not support this request. We agree with the staff conclusion that this would produce confusion, and, therefore, we shall not require Edison to establish such a specific rate for low-pressure sodium-vapor lamps in Schedule No. LS-2.

Edison opposes including low-pressure sodium-vapor lamps under Schedule No. LS-1. Edison states that it is in the process of converting all of its company-owned streetlights to high-pressure sodium-vapor. Edison recites that, as part of this program, it has attempted to optimize the number of lamp sizes and the types of high-pressure sodium-vapor fixtures and lamps which the utility would install. The stated purpose of this program is to reduce costs while at the same time obtaining the benefit of a more efficient light source.

12/ Edison now has pending before the Commission a proposal to modify Schedule No. LS-2 (Advice Letter 531-E, dated August 7, 1980) to clearly specify that the schedule includes service to low-pressure sodium-vapor lamps. Accordingly, we do not consider this point to be at issue.

Edison states that, at present, the most common company-owned facilities are mercury-vapor streetlights and that these are easily convertible to high-pressure sodium-vapor, whereas the entire fixture must be changed to adapt to low-pressure sodium-vapor lamps. This, says Edison, would in many cases increase the cost of conversion.

Edison also mentions that by standardizing on lamps and fixtures, it has been able to obtain favorable quantity prices from the major American manufacturers of these lamps and fixtures. Edison does not know of any domestic manufacturer which now produces low-pressure sodium-vapor lamps and fixtures.

Long Beach contends that the low-pressure sodium-vapor lamp is more energy efficient than the high-pressure lamp. The record is far from conclusive on this point. Further, the evidence indicates that, at least as far as Edison's system is concerned, the high-pressure sodium-vapor lamp is more cost efficient than the low-pressure sodium-vapor lamp.

The record in this proceeding does not provide a proper basis for ordering Edison to include low-pressure sodium-vapor lamps under its Schedule No. LS-1. It is clear that this is not the appropriate proceeding for us to make a determination on the highly technical engineering and economic aspects of the relative merits of high-pressure versus low-pressure sodium-vapor streetlighting service.

The staff recommends that Schedules Nos. LS-1 and LS-2 be closed to new installations except sodium-vapor lamps. We note Edison has already closed Schedule No. LS-1 to incandescent and mercury-vapor lamps; therefore, this point is not at issue. We will not adopt the staff recommendation with respect to closing Schedule No. LS-2, because it would deny service to any governmental jurisdiction if it were to add a single nonsodium light to its existing system.

The staff brings out that the present Edison streetlighting tariffs are unnecessarily complex and difficult to understand. The staff recommends that Edison be required to revise its streetlighting tariffs to provide clear, concise, and understandable rate schedules. The City of Long Beach concurs in this recommendation. The order herein will require Edison to make the appropriate revisions to its tariffs.

The staff concurs in the streetlighting rate adjustments which were proposed by Edison. These rates did not become an issue in the proceeding. We will, therefore, adopt Edison's rate proposals for streetlighting.

i. Christian Science Churches in <u>Southern California (Christian Science Churches)</u>

Christian Science Churches presented the testimony of a registered engineer who demonstrated a thorough familiarity with the operations of the Christian Science Churches, as well as a good working knowledge of the tariffs of Edison and other California electric utilities.

The typical Christian Science Church has a very low energy consumption in relation to demand (about 10.7 kWh per kW). These churches generally hold services for one hour on Sunday mornings and one hour on Wednesday evenings. In many months these two sessions comprise the entire use of the auditorium, which is responsible for establishing the church's peak demand as well as accounting for a large part of the energy consumed. The remaining electricity consumption is from intermittent minor space usage for such purposes as offices, which are used three days per week during the mornings, and committee rooms, which may be used once or twice per week.

Edison's last general rate increase, which became effective January 1, 1979, had a heavy financial impact on the Christian Science Churches. According to their engineer, the change in Edison's rates dramatically altered the relationship between demand charges and energy charges as a percentage of the typical church billing. In 1978 that relationship was roughly 25 percent demand charges and 75 percent energy charges. At the beginning of 1979 the relationship was reversed, to about 75 percent demand charges and 25 percent energy charges. The churches experienced an overall average increase in billing of about 65 percent.

The showing of the Christian Science Churches in this proceeding clearly demonstrates the need for the development by Edison of optional tariff offerings such as are afforded by the Schedule No. A-12 demand rate and the Schedule No. A-1 nondemand rate of PG&E.

The order herein will direct Edison to work with our staff toward developing such an alternative offering.

5. Adopted Rates

a. General

Relatively few of the specific rate proposals of the several interested parties are adopted herein; however, we have given the evidence they presented due weight in our deliberations, and many of their recommendations are reflected in the adopted rate design and rate spread.

With one exception, the design of the adopted rates conforms to the following general pattern throughout all of Edison's schedules. We are: (1) decreasing no rates; (2) increasing no customer charges, demand charges, or connected-load charges; (3) increasing energy rates only; and (4) eliminating all declining block rates. It is our opinion that this rate pattern will be a meaningful step toward greater energy conservation and will, at the same time, promote equity within and among the several customer groups.

The record in this proceeding permits us to design rates for Edison which will approach more closely the cost of performing the service. We are accomplishing this, in large measure, by placing substantial reliance on the marginal costs developed by the Commission staff.

Table VI-V shows a summary of adopted base revenues and Table VI-W shows a corresponding summary for total revenues (including currently effective ECAC amounts). Table VI-X shows a comparison of the average rate in cents per kWh, for both base rates and total rates by customer group.

b. Domestic Rates

The most significant departure from cost-based rate design in this decision is made in the residential class for lifeline service. The policy enunciated by the California Legislature in mandating the establishment of lifeline rates for essential levels of utility service makes it clear that cost of service considerations should not determine rate levels for lifeline service. However, because of the substantial increases in average system rates which have occurred since lifeline service was established and because of the high proportion of residential sales which are made at lifeline rates, some sharing by lifeline customers of the burden of higher energy costs is necessary.

We concur in the CEC recommendation with respect to the elimination of the domestic customer charge. This is consistent with State lifeline policy and, with our view of marginal cost pricing, and it will enhance the cost-effectiveness of conservation measures. We will provide for recovery of the equivalent of the revenues from the $2 monthly customer charge through an increase in base rates for the basic lifeline quantity. Thus, both small users and large users will bear their equitable share of this revenue requirement.

We will not eliminate other forms of customer charges in other schedules pending more definite study on the effect of such a change.

At the present time, there is a single base rate for the basic lifeline allowance of 240 kWh and all nonlifeline usage. By apportioning a greater amount of the domestic class revenue increase to nonlifeline usages and recovering customer charge revenues as described above, we will be able to maintain this single base rate.

The present base rate for water and space heating and life support lifeline usages is at a lower level than the rate for basic lifeline and nonlifeline usages. While we concur with Edison's and the staff's goal of eliminating the lower rate for lifeline above 240 kWh, we are concerned with the magnitude of the increases that would occur for such usages if a single rate were to be adopted in one step. We will, therefore, eliminate the differential in these rates in two steps, the first step to take effect at this time, and the second step to take effect in 1982 when the one-step increase authorized herein goes into effect. Concurrently we establish the air-conditioning lifeline base rate to be the same as all other lifeline base rates at less the 240 kWh level.

We are making several changes in multifamily residence rates. Because of the elimination of the customer charge in Edison's domestic rate, customers taking service under Schedules Nos. DMS-1 and DMS-2 will no longer be entitled to collect this charge from their submetered customers. With this elimination, and in order to provide DMS-1 and DMS-2 customers with a discount equivalent to the estimated cost to Edison of providing comparable service to submetered customers, it will be necessary to change the present percentage discounts under these schedules. We concur in the staff's recommendation that no more than the equivalent of the $2 customer charge is necessary to compensate Schedule No. DMS-1 customers, and we therefore authorize the equivalent discount of 33 percent applied to lifeline quantities.

c. General Service Rates

For Schedule No. GS-1, in keeping with our overall rate pattern, we will maintain the monthly service charge at its present $4.50 level. We will adopt an energy charge based on the staff recommendation in Exhibit 46, adjusted to the level of increase authorized in this decision.

For Schedule No. GS-2, we will hold the demand charge for the first 20 kW or less at the present $76.00 per month and excess demand at the present $3.80 per kilowatt. The present declining three-block energy charge will be changed to a single-block rate based on the staff proposal in Exhibit 46.

For Schedule No. A-7, we will hold the demand charges at the present level of $800.00 for the first 200 kW or less and $3.30 for each kW of excess demand. Here again, the present declining three-block energy rate will be replaced by a single-block rate based on the staff proposal in Exhibit 46.

d. Time-of-Use Rates

In Schedule No. TOU-8 will be an apparent departure from our rate design pattern in that the customer charge is being changed from $1,075.00 per month to $560.00 per month. We do not regard this as a rate reduction, per se. The main reason for this change is that we are making this schedule mandatory for all general service customers with demands above 500 kW, down from the present 1,000 kW. The group of customers with demands in the range between 500 kW and 1,000 kW would be subjected to an inequitably high customer charge if we were not to make this concurrent change.

The demand charges in Schedule No. TOU-8 are being held at their present level of $5.05 per kW of on-peak demand and $0.65 per kW of mid-peak demand. We are adopting energy charges based on the design of staff Alternative III, and we are retaining the seasons and time periods as now specified in Edison's tariffs. We are expanding Schedule No. TOU-8 to include customers with demands above 500 kW and accordingly take official notice of Decision No. 90146. We will provide an additional $250,000 per year in disbribution expenses for a simple visual display meter for each Schedule No. TOU-8 customer in need of such a meter. The customers will provide the necessary wiring for the meter.

With respect to the experimental TOU-GSX and TOU-D schedules, we are adopting Edison's proposals. We are retaining all 14 of these schedules with present relationships between time-varying components and charges to preserve their experimental validity. In addition, we are directing Edison to work with the staff toward developing an optional time-of-use offering similar to that provided by Schedules Nos. A-20A through A-20D of PG&E.

We are concerned with inequities which may arise in assessing the significant demand charges in Edison's GS-2 and A-7 schedules on a basis which does not differentiate by time-of-use and of billing demand on the basis of not less than 50 percent of the highest demand in the preceding 11 months. We are, therefore, directing Edison to cooperate with our staff and affected customer groups in developing optional general service time-of-use rates to be available within 90 days. This rate is to be available within three months to 1,000 customers with monthly maximum demands up to 500 kW. Priority for such service during off-peak hours, such as the examples presented by the Christian Science Churches, and those customers having significant seasonal variation in use, such as the service referred to by the Coachella Valley Association of Governments.

Edison is also directed to submit alternate tariffs and recommendations for the Commission's consideration on: (1) the elimination of ratchets on the billing demand under the GS-2, A-7, TOU-8, and any other schedules (any offsetting revenues should be recovered within these schedules); and (2) a program for conversion of all GS-2 and A-7 customers to time-of-use rates.

e. Agricultural and Pumping

For Schedule No. PA-1, we will deny Edison's request to institute a customer charge. We will change the annual service charge of $11.95 per hp per year to a charge of $1.00 per hp per month. We will adopt a single-block energy charge as proposed in staff Alternative II.

For Schedule No. PA-2, we will retain the present demand charges of $281.25 for the first 75 kW and $3.75 for each excess kW. To replace the present declining three-block rate, we will adopt a single-block energy charge, as proposed by the staff in its Alternative I. We will require Edison to file experimental and/or optional time-of-use rates within three months, as a continuation of the statewide program of innovative agricultural rate design which provides an opportunity for agricultural customers to shift load. The estimated $750,000 loss in revenue due to load shift will be recovered from the agricultural and pumping customer group in our rate design.

f. Streetlighting

For Schedules Nos. LS-1 and LS-2 we will adopt Edison's rate proposal as amended in the allocation to customer groups. In addition, we will direct Edison to work with the staff toward revising its streetlighting tariffs to provide clear and concise wording, similar to the tariff schedules of PG&E and SDG&E.

TABLE VI-V

Southern California Edison Company
Summary of Adopted Revenue Increases
(Base Revenues Only)

Test Year 1981
(Thousands of Dollars)

Customer Group	Average Number of Customer Months	1981 Est. Sales GWh	Base Revenue: At Present Rates	Base Revenue: At Adopted Rates	Increase in Base Revenue: Amount	Increase in Base Revenue: Percent
Domestic						
Lifeline	2,786,025	8,912.1	273,377.2	291,302.2	17,925.0	6.6
Nonlifeline	62,260	7,454.2	183,594.2	259,098.7	75,504.5	41.1
Sub Total	2,848,285	16,366.3	456,971.4	550,400.9	93,429.5	20.5
Lighting & Small Power	315,805	11,348.5	309,554.7	377,327.0	67,772.3	21.9
Large Power	3,374	4,385.6	74,355.5	100,689.9	26,334.4	35.4
Time-of-Use	2,155	19,337.1	293,111.8	385,841.3	92,729.5	31.6
Agricultural & Pumping	32,926	1,833.9	39,835.2	49,341.5	9,506.3	23.9
Street Lighting	8,215	543.7	31,750.8	36,161.5	4,410.7	13.9
Total	3,210,760	53,815.1	1,205,579.4	1,499,762.1	294,182.7	24.4

TABLE VI-W

Southern California Edison Company
Summary of Adopted Revenue Increases
(Total Revenues, Including ECAC)*

Test Year 1981
(Thousands of Dollars)

Customer Group	Average Number of Customer Months	1981 Est. Sales GWh	Total Revenue: At Present Rates	Total Revenue: At Adopted Rates	Increase: Amount	Increase: Percent
Domestic						
Lifeline	2,786,025	8,912.1	468,538.5	486,463.5	17,925.0	3.8
Nonlifeline	62,260	7,454.2	531,113.0	606,617.5	75,504.5	14.2
Sub Total	2,848,285	16,366.3	999,651.5	1,093,081.0	93,429.5	9.3
Lighting & Small Power	315,805	11,348.5	778,728.8	846,501.1	67,772.3	8.7
Large Power	3,374	4,385.6	255,612.4	281,946.8	26,334.4	10.3
Time-of-Use	2,155	19,337.1	1,092,314.1	1,185,043.6	92,729.5	8.5
Agricultural & Pumping	32,926	1,833.9	115,630.3	125,136.6	9,506.3	8.2
Street Lighting	8,215	543.7	53,172.1	57,582.8	4,410.7	8.3
Total	3,210,760	53,815.1	3,295,109.2	3,589,291.9	294,182.7	8.9

*ECAC Revenue Based on CPUC Staff Proposed January 1, 1981, Billing Factors

TABLE VI-X

Southern California Edison Company
Comparison of Average Rate by Customer Groups
Test Year 1981

By Customer Groups	Average Rates ¢/kWh: Present Base Rates	Increase In Base Rates	Adopted Base Rates	ECAC Rates	Total Avg. Rates
Domestic					
Lifeline	3.068	0.201	3.269	2.190	5.459
Nonlifeline	2.463	1.013	3.476	4.662	8.139
Sub Total	2.792	0.571	3.363	3.316	6.679
Lighting & Small Power	2.729	0.598	3.327	4.133	7.460
Large Power	1.695	0.601	2.296	4.133	6.429
Time-of-Use	1.516	0.479	1.995	4.133	6.128
Agricultural & Pumping	2.172	0.519	2.691	4.133	6.824
Street Lighting	5.840	0.811	6.651	3.940	10.591
Total	2.240	0.547	2.787	3.883	6.670

6. Other Rate Design Matters

a. Cogeneration

(1) Staff Recommendations

In Decision No. 89711, supra, we ordered Edison to review and catalog for its service area all existing and potential auxiliary power sources and cogeneration projects and their ability to contribute power during its high demand periods. As a result of that order, Edison developed a program to document existing and planned auxiliary generation and to reassess the cogeneration potential within its service territory.

Edison's preliminary report on its survey was submitted in April 1979, and the final report was submitted in August 1979 in compliance with the order. The survey results indicate a significant potential for cogeneration utilizing steam boilers and hot exhaust gases. Among Edison's industrial customers, 267 use boilers in their processes, and 212 of them reported having high-temperature exhaust gases available for cogeneration.

The staff reports that Edison is effectively following up on the survey responses. Four engineers in the main office are being assisted by field service personnel in contracting potential cogenerators. Edison has analyzed the survey responses and contacted the most promising ones first. In addition, field service personnel have been trained to estimate cogeneration potential in making their normal field contacts.

The development of parallel generation facilities can be of significant value to Edison and its customers in terms of reducing the load obligation Edison must serve, thereby reducing the need to construct new generating capacity and/or encouraging the conservation of natural resources. Therefore, Edison's solicitation of customer participation in the development of cost-effective parallel generation results in net conservation of resources and has an acceptable environmental impact.

About 460 MW of cogeneration potential has been identified and reported in the Cogeneration Projects Quarterly Report to the Commission. These projects are primarily in the large (Schedule No. A-7) and very large (Schedule No. TOU-8) power customer classifications. Additional potential may be identified in the current study by the Air Resources Board pursuant to the Calvo Bill (AB 524). Edison's estimate of 1981 costs and results of the cogeneration program are presented in Table VI-Y.

TABLE VI-Y

Cogeneration Activity
1981 Summary of Estimated Costs and Results

Component	Estimated Annual Cost	Estimated Annualized Savings	Estimated Annualized Demand Reduction	Method of Measurement
Cogeneration Contracts	$162,800	620,000,000 kWh	26 MW	Installations
Cogeneration Studies	654,800	___	___	Study Reports
Totals	$817,600	620,000,000 kWh	26 MW	

The staff has reviewed Edison's cogeneration program and considers it to be effective. It is of the opinion that the estimated program cost of $817,600 for test year 1981 is reasonable.

The staff offers the following recommendations concerning Edison's cogeneration program:

"A. Edison should perform the studies of its system air emissions necessary for potential cogenerators to obtain any air quality permits and emission offsets required by law.

"B. Edison should perform the studies of its system fuel use necessary for potential cogenerators to obtain any Fuel Use Act exemptions required by the U.S. Department of Energy.

"C. Edison should assist potential cogenerators in obtaining current knowledge of pollution control and environmental regulations.

"D. Edison should apply all possible vigor and imagination to its cogeneration program with the goal of bringing the maximum amount of cogeneration on-line in the shortest possible time.

"E. Edison should prepare a financial analysis program for the confidential use of cogenerators in their cost/benefit analyses.

"F. Edison should be encouraged to finance or participate in the financing of cost-effective cogeneration projects, particularly if the project sponsor is unable to obtain the necessary financing without utility participation."

(2) Recommendations of Kimberly-Clark Corporation (Kimberly-Clark)

Kimberly-Clark produced as a witness the engineering manager of its consumer products mill at Fullerton. His testimony concentrated upon the problems confronting a typical southern California industrial manufacturer in implementing the national policy of encouraging energy conservation through the development of cogeneration. He suggested that, because of the recent issuance by FERC of rules implementing PURPA Section 210, it would be an opportune time for us to develop new rates and rules to encourage the growth of cogeneration in California.

In Kimberly-Clark's view, there have been two factors which have discouraged the growth of cogeneration in the past:

> "First, the high rates established for standby power were premised on the assumption that any backup energy would be coincident with the utility's system peak. Second, utilities have only been willing to purchase surplus cogenerated energy at low rates equivalent to 'dump prices' paid in regional power pools. Unless proposed rates contain sufficient incentives on these two points, Kimberly-Clark cannot realistically commit the extensive capital necessary to engage in cogeneration."

Economic analysis by Kimberly-Clark of the current offering by Edison suggests that the utility's "buy-sell" proposal would not afford the economic incentive necessary for the paper products company to engage in cogeneration. The buy-sell offering's central provision, as Kimberly-Clark understands it, is that a cogenerator would sell all of its electrical output to Edison, while meeting its own needs for electrical energy under a variety of existing purchase schedules. Kimberly-Clark would prefer an alternative approach, whereby it would sell to the utility only the excess of cogenerated energy beyond that necessary to satisfy its own needs. Under this approach, if suitable rate levels were established, the witness testified, a cogenerator like Kimberly-Clark could generate energy partially satisfying its internal needs; or generate just enough to meet internal needs; or generate sufficient energy to satisfy all internal needs and produce a consistent surplus for sale to the utility.

Kimberly-Clark's witness testified that there are other deficiencies in the rates offered to cogenerators by Edison. He said that, should Kimberly-Clark become a cogenerator under the existing standby schedules, it could become liable for a backup charge of approximately $11,000 per month, plus an additional $8,000 per month should it take standby power even once; and that, furthermore, any power taken from Edison would have to be on an interruptible basis. He stated that such charges, ostensibly designed to maintain adequate reserve capacity without recognition of diversity, in effect penalize cogenerators and frustrate our national energy policy, which seeks to encourage cogeneration.

Kimberly-Clark offered a comprehensive cogeneration rate proposal involving the tariffs of SoCal as well as Edison. It raises a number of issues not otherwise treated in this proceeding. We hereby direct the staff to review the rate proposal so that it may have the benefit of Kimberly-Clark's study as an aid in the ongoing administration of the Commission's cogeneration activities.

b. PURPA Compliance

PURPA established a series of ratemaking and regulatory standards which must be considered on a utility-by-utility basis by each state regulatory authority.

Title I of PURPA is concerned with electric utilities. Its purposes are set forth as "encouraging (1) conservation of energy supplied by electric utilities; (2) the optimization of the efficiency of use of facilities and resources by electric utilities; and (3) equitable rates to electric consumers." It requires that each state regulatory authority consider a series of federal standards and make a determination for each standard of whether its adoption will promote the three purposes.

There are two separate groups of standards: "ratemaking standards" (those established by Sec. 111) and "regulatory standards" (established by Sec. 113). The former group involves procedures for designing the structures of electric rates, while the latter pertains to certain utility practices. Lifeline rates are not strictly established as a federal standard, but consideration of whether or not to adopt lifeline rates is a requirement of Title I (Sec. 114).

Both the ratemaking and regulatory standards must be considered in public hearings, and both require a written determination of appropriateness relative to the Title I purposes. We must decide whether each ratemaking standard would contribute to the purposes and, if so, whether or not to implement it for each utility. The regulatory standards must be adopted if we determine that they would carry out the purposes of the title, are otherwise appropriate, and are consistent with state law.

In Exhibit 52 the staff proposes the manner in which we should implement PURPA requirements in this proceeding. The following is a statement of the recommendations in that exhibit.

> "1. Staff has recommended that the Commission adopt for SCE the following ratemaking standards as contributing to the purposes of Title 1 of PURPA.
>
> "A. Cost of Service
> B. Declining Block Rates
> C. Seasonal Rates
> D. Interruptible Rates
> E. Load Management Techniques
>
> "Implementation of these standards in the present proceeding can be accomplished through reliance on the staff presentations concerning marginal cost and the application of marginal cost to rate design.
>
> "2. The regulatory standard of Information to Consumers should be adopted by the Commission, and Edison should be directed to implement the standard."

The staff states that we should include a specific finding in this decision with respect to the adopted rates to the effect that the purposes of Title I have been met. The staff points out that neither Edison, nor any other party, has made any showing or recommendation specifically pertaining to the implementation of PURPA and that, therefore, the staff recommendations, as summarized above, should be adopted in their entirety.

The staff testified that the remaining ratemaking and regulatory standards embodied in PURPA have either been adopted by us or are being considered in separate proceedings. One such standard is cost of service. (Sec. 111(d)(1).) The staff believes that since we adopted marginal cost as a measure of the cost of service for ratemaking in Decision No. 91107, supra, the principal thing that remains to be done with respect to the cost of service standard in this application is to apply the marginal cost evidence.

In regard to the standard respecting declining block rates (Sec. 111(d)(2)) at the present time, Edison has in effect several rates in which the energy charge per kWh decreases as energy use increases. Such rates are included in Schedules Nos. A-7, GS-2, P-1, PA-1, and PA-2. Edison proposes, and the staff concurs, in the revision of these rates to eliminate the declining block energy charge to the extent such revision can be accomplished without unduly severe customer impacts. The staff recommends that we should adopt and implement the declining block rates standard. Time-of-day rates are the subject of another PURPA standard. (Sec. 111(d)(3).) We have heretofore adopted this standard. The staff recommends that, in order for the cost-effectiveness of extending TOU rates to smaller customer groups to be evaluated, we should require Edison to prepare cost-effectiveness analyses consistent with the criteria specified in Section 115(b).

With respect to seasonal rates, (Sec. 111(d)(4)), the standard provides that rates will be designed to reflect seasonal differences in costs. As demonstrated by the marginal costs studies in this proceeding, there exists some variation in Edison's costs between the summer and winter seasons. This differential reflects the higher summer loads which impose additional capacity costs and greater energy costs on the system. The staff points out that rates which reflect these differences shift the additional cost burden on to those who contribute to the higher summer demands. Accordingly, it recommends that we should find that seasonal rates would promote the purposes of Title I and that it should adopt the seasonal rate standard for Edison. The staff suggests that implementation of this standard be accomplished gradually, with primary emphasis being given to the seasonal variation of time-of-use rates.

The interruptible rate standard (Sec. 111(d)(5)) requires the offering of interruptible rates to industrial and commercial customers and specifies that such rates be based on the cost of providing interruptible service. The staff recommends that we make a finding in this proceeding that sufficient evidence has been presented to demonstrate that the interruptible rate standard will contribute to conservation, efficiency, and equity, and that we adopt the standard for Edison.

The load management techniques standard (Sec. 111(d)(6)) requires that electric utilities offer techniques for load management when the state regulatory authority has determined that the techniques would be practicable and cost-effective, would be reliable, and would result in energy or capacity management advantages to the utility. The record indicates that Edison's programs must be seen as experimental; therefore, the reliability and energy or capacity management advantages, as well as the cost-effectiveness, for many programs cannot be determined with certainty at this time. There is, however, sufficient evidence that cost-effective load management techniques will contribute to the Title I purposes, and the staff recommends that this standard be adopted for Edison. The staff also recommends that we require Edison to present cost-effectiveness analyses for programs which we identify as being reliable and likely to result in energy or capacity management advantages.

The information to consumers standard (Sec. 113(b)(3)) provides that the electric utilities regularly transmit information to all customers regarding the applicable rate schedules. While the manner of transmittal is left to the discretion of the state regulatory authorities, Section 115(f) specifies the nature of the information and the regularity with which it must be provided. The amount of rate information available to consumers is an important factor in the effectiveness of conservation-oriented rates.

Customers must be made aware of lifeline quantities and nonlifeline prices in order to respond to the rate schedule by reducing nonlifeline usage. The design of nondomestic rates also assumes some knowledge on the part of the consumers of the prices they are being charged. Our policy of designing rates to maximize conservation requires that the rate information be provided to the customers.

The staff recommends we adopt the information to consumers standard and that we require Edison to comply with the procedures outlined in Section 115(f).

With respect to the cost of service standard (Sec. 111(d)(i)), the methodology for determining the costs is left to the discretion of the state regulatory authority, but such methodology must consider time variations in costs as well as distinctions among customer-, energy-, and demand-related costs. In addition, the costing methodology should take into account the changes in total costs if

> "(A) additional capacity is added to meet peak demand relative to base demand; and
>
> "(B) additional kilowatt hours of electrical energy are delivered to electric consumers." (Sec. 115(a)(2).)

The staff offers the following opinion relating to the cost of service standard:

"In prior decisions, this Commission has determined that the design of electric rates should consider the marginal cost of service. Marginal cost studies submitted by staff and the utilities in these prior proceedings demonstrate the time-varying nature of electric costs, distinguish among customer-related, demand-related, and energy-related costs and are based on changes in total cost resulting from additions to capacity and energy. Consequently, it can be seen that these studies comport with the PURPA description of cost of service."

VII. PETITIONS

A. TURN PETITION FOR AWARD

On March 28, 1980 TURN, a consumer organization, on its own behalf and on behalf of the residential customers of Edison, filed a petition with this Commission for an immediate award of $15,000 as participation funding in this rate proceeding pursuant to Section 122(b) of PURPA.

On April 23, 1980 TURN's petition was denied by an Administrative Law Judge's Ruling for the following stated reasons:

"TURN alleges that its representation is essential to the interests of residential customers. However, TURN does not specify in what subject, or in any other particulars, how it would represent these allegedly otherwise unrepresented customers, or how it would materially contribute to the proceeding. For lack of specificity alone, the Commission cannot at this time make an award on the basis of TURN's petition.

> "Furthermore, the subject of such intervenors' awards pursuant to PURPA is before the Commission in OII 39, which is pending. Thus, no mechanism has been adopted at this time that would enable an award to be made to TURN pursuant to PURPA."

On June 17, 1980 TURN filed an appeal requesting that the Commission nullify the Administrative Law Judge's Ruling and grant TURN the relief requested, or, in the alternative, that TURN's petition and the appeal be considered by the Commission and a final determination made.

Because of extenuating circumstances, TURN was permitted to enter an appearance through staff counsel at the prehearing conference in this application. TURN has not otherwise participated in any manner in this proceeding except to file the petition and appeal we are here considering. TURN was not present at any time during the two prehearing conferences and over 50 days of public hearings which were held in this matter prior to submission on July 11, 1980. Initial briefs and reply briefs have been filed. None was received from TURN.

TURN is not an appearance to this proceeding. Despite the appearance entered on behalf of TURN by staff counsel, TURN never thereafter physically appeared or participated in the hearings. Parties must be present to enter an appearance. In this instance our Administrative Law Judge and staff counsel acted with good intentions and were accommodating on the expectation TURN would subsequently appear. It did not. Thus, we find TURN is not a party to this proceedings.

TURN has not demonstrated the materiality of any showing over and above that made by the staff. Under the circumstances, we will deny TURN's petition and appeal.

B. CIEC PETITION FOR PROPOSED REPORT

On July 11, 1980, the date of submission of this proceeding, CIEC petitioned the Commission pursuant to Rule 78 for the issuance of an Administrative Law Judge's Proposed Report prior to final decision.

In its petition, CIEC submits that the issuance of such a report, with the opportunity for comment thereon by interested parties, would aid the Commission in its determination of the numerous and complex issues in this proceeding.

We will deny CIEC's petition for a proposed report on the following grounds:

1. Under the Commission's Regulatory Lag Plan no provision is made for the proposed report procedure requested by CIEC.

2. The Commission's Rules of Practice and Procedure call for additional time intervals of 20 days for filing exceptions to proposed reports and 15 days for filing replies to exceptions.

3. By filing the petition for a proposed report the last day of the hearing all opportunity was foreclosed for possible expediting conclusion of the hearing to allow the additional time required for the proposed report procedure.

4. The proposed report procedure would entail delay in the decision process in this proceeding and would impair the likelihood of the decision's being rendered in conformity to the Regulatory Lag Plan schedule.

C. AIR PRODUCTS' PETITION

On July 10, 1980, the day before submission of this proceeding, counsel for Air Products and Chemicals, Inc. (Air Products) requested authorization from the assigned Administrative Law Judge to present new testimony directed to the interpretation and construction of Edison's Schedule No. TOU-8-I. The Administrative Law Judge denied the request.

On July 17, 1980 Air Products filed a petition addressing the same request to the Commission.

We take notice of the following particulars regarding the petition of Air Products:

1. The issue on which Air Products desires to introduce evidence arises from Decision No. 91751 dated May 6, 1980 in OII No. 43.

2. Air Products entered an appearance in this application on June 10, 1980.

3. Air Products waited until July 10, 1980 to make its request to introduce evidence.

We further take notice of subsequent action of the Commission in denying Edison's petition for rehearing of Decision No. 91751 in OII No. 43. Decision No. 92169, dated August 19, 1980, in part "ordered that the second paragraph of page 21 of Decision No. 91751 shall be modified as follows:

> "The staff further contends that these five customers are receiving preferential rates, and therefore, should be interrupted when necessary to preserve the integrity of any major utility system in California. While we believe that the present wording of Edison's Tariff Schedule TOU-8-I

is not in keeping with the intent of the statewide load reduction plan, we also recognize that this tariff as presently worded, was in effect and referred to in Edison's approved 1979 plan and that because of the absence of specific notice of this issue, other testimony on the appropriate language of TOU-8-I may be elicited. <u>We will therefore consider holding further hearings in a separate proceeding to resolve this significant issue. The proceeding will be designed to allow and encourage participation by the utilities, the staff, and interested parties</u> in order to develop a record upon which a uniform standard can be established to define the procedures and circumstances under which a utility's interruptible customers will be interrupted during a Stage II alert."

It should be clear from the underlined sentences in the foregoing quotation we have made provision outside of the instant proceeding for consideration of interruption of Schedule No. TOU-8-I customers. Therefore, we will not grant Air Products' petition or prejudge the testimony it wishes to present.

D. PETITION OF COACHELLA VALLEY ASSOCIATION OF GOVERNMENTS (CVAG)

CVAG asks that this Commission:

1. Extend the lifeline allocation for air conditioning from the present 500 kilowatt-hours per month to 1,500 kilowatt-hours per month for the six months May through December.

2. Implement a system of lifeline banking so that consumers may carry over unused lifeline allocation from one month to another.

3. Eliminate or modify the demand charge that is presently levied on business operations in the low desert area because of extreme hot weather conditions.

4. Create a new service zone area for the purposes of rate applications that would include only the low desert area.

5. Initiate a special study that would analyze the cost of energy in relation to the existing climatic conditions of the low desert area.

We recognize the serious impact that electric cost increases have had on domestic customers, particularly those in Edison's service area subject to the highest summer temperatures. We are, therefore, requiring Edison to make a special zero-interest financing conservation program available to domestic customers in this area as soon as possible. We are also directing the staff to proceed with a statewide review of lifeline air-conditioning allowances. We will also have the staff examine the relationship between lifeline and nonlifeline ECAC rates for commencement of air-conditioning allowances this summer.

The foregoing actions together with modifications to both the domestic and small business basic rates being adopted in this decision should ameliorate to some extent the rate impacts being experienced in the low desert area. We are, however, greatly concerned over the points raised by CVAG, and we shall respond in detail to CVAG by letter.

VIII. FINDINGS AND CONCLUSIONS

A. FINDINGS OF FACT

1. The adopted results of operations for the test year 1981, and each constituent element thereof, as shown in Table III-A, provide a proper and reasonable basis for determining Edison's California jurisdictional revenue requirements.

2. The level of gross revenues produced by Edison's base rates for electric service is not sufficient to meet Edison's revenue requirement.

3. Estimated sales and revenues for test year 1981 and year 1982 are subject to significant fluctuations.

4. A reasonable method for treating such revenue fluctuations is to refund any base rate revenues for 1981 exceeding our adopted base rate revenues of $1,499,775,000, for the six major customer groups: Domestic, Lighting and Small Power, Large Power, Time-of-Use, Agricultural Power, and Streetlighting.

5. The capital structure described in Table IV-E of the opinion is required to afford Edison an opportunity to maintain its financial credibility and integrity, to attract capital at a reasonable cost, and to compensate its investors for the risks assumed over the next two years.

6. Edison's actual cost of long-term debt and preferred stock over the next two years may reasonably be expected to exceed the costs in this record because of the continuing effects of inflation. Accordingly, a rate of return of 14.95 percent on Edison's common equity is justified and within the zone of reasonableness for the 1981 test year.

7. A 14.95 percent return on common equity, when applied to the capital structure described in Table IV-E, will, over the two-year period beginning January 1, 1981, yield an 11.20 percent average rate of return on rate base for Edison's California jurisdictional electric operations. This level of return on common equity will provide an after-tax interest coverage of 2.69 times over the two-year period.

8. To earn an average rate of return of 11.20 percent over the two-year period 1981-1982, Edison's base rates for electric service should be increased, effective January 1, 1981, to provide an increase of $294,196,000 in annual gross revenues and further increased, effective January 1, 1982, to provide a further increase of $91,927,000 in annual gross revenues.

9. The rate of return on common equity and rate base, together with the increased revenue requirement herein found to be justified, are expressly authorized with the understanding that the next earliest test year to be used in establishing Edison's revenue requirement will be 1983.

10. The adopted test year estimated results of operations found reasonable are in compliance with the Federal Wage and Price Guidelines issued by the Council on Wage and Price Stability.

11. The rate schedules set forth in Appendix B will afford Edison an opportunity to collect the additional authorized revenues in a just, reasonable, and nondiscriminatory manner.

12. Marginal costs provide the acceptable approach to allocating cost recovery among customer groups.

13. The increase in base revenue by customer group shown on Table VI-V and in total revenue shown on Table VI-W are based on marginal cost and are reasonable.

14. No group of customers should be completely shielded from the burden of increasing costs. To do so would provide a false economic signal which would be antithetical to conservation.

15. It is reasonable to eliminate the domestic customer charge and to recover offsetting revenues through increased domestic energy charges.

16. Not increasing customer charges or service charges will promote conservation and is in keeping with PURPA standards.

17. Eliminating declining block rates for energy will promote conservation and is in keeping with PURPA standards.

18. It is reasonable and in the interest of conservation to obtain essentially all of the gross revenue increase authorized herein through higher charges for electric energy.

19. The rates adopted herein meet the purposes of Title I of PURPA by contributing to the following ratemaking standards: Cost of Service; Declining Block Rates; Seasonal Rates; Interruptible Rates; and Load Management Techniques. This has been accomplished by means of the rate design employed herein.

20. The public interest requires that Edison should implement the PURPA regulatory standard of Information to Consumers.

21. The average system rate for Edison's electric service now exceeds the January 1, 1976 level of residential lifeline rates by well over the prescribed statutory differential of 25 percent as set forth in Section 739(c) of the Public Utilities Code.

22. The moderate electric revenue rate increase for Edison's residential lifeline service is less than the total average system increase. The resulting residential total lifeline average electric energy rate is less than the total average system energy rate. This relationship is consistent with the Commission's policy as expressed in recent decisions.

23. Edison's customer groups' rate relationships should be maintained in subsequent ECAC proceedings by applying a uniform ¢/kWh basis for each customer group.

24. The adopted rates will move the residential group of customers closer to the cost of service relationship shown to be justified in this proceeding. The adopted rates reflect a reasonable cost rate relationship both within and among the several groups of customers.

25. The apportionment of the authorized increase to the several customer groups is just and reasonable.

26. Embedded cost of service reflects historical construction costs and depreciation of existing plant which are not relevant to current costs of meeting changing demand for electric service.

27. Embedded cost of service, although a factor to be considered in setting rates, is not an appropriate measure for determining the conservation impact of a particular rate design.

28. It is equitable that changes in electric rates for each major customer group reflect the cost to the utility of furnishing the last increment of additional system supply.

29. Directing rates for marginal usage by each major customer group toward the cost to the utility of furnishing an additional unit of system supply will provide appropriate signals to customers as to the cost of added energy consumption and will provide the appropriate incentive for conservation.

30. Marginal costs of electric generation and transmission plant measure the appropriate cost to the utility of being required to furnish the last increments of system supply.

31. The marginal cost data utilized by the staff in Exhibit 46 are reasonable for the purpose of establishing marginal cost of generation and transmission for this proceeding.

32. Making Schedule No. TOU-8 mandatory for all general service customers with demands above 500 kW will promote energy conservation and load management. This finding contemplates that limited optional/experimental time-of-use service will be available to general service customers with demands above, 50 kW and to agricultural customers with loads of 35 hp and above.

33. It is reasonable to eliminate Schedule No. P-1 and transfer customers now served under that schedule to Schedule No. GS-1 or GS-2.

34. Edison's proposals as to special conditions for its experimental and agricultural time-of-use schedules are reasonable.

35. In Schedule No. DM for Zones H and V it is necessary to study further the reduction of additional air-conditioning lifeline allowances to 225 kWh and 400 kWh, respectively.

36. It is reasonable to increase the 10 percent discount in Schedule No. DMS-1 to reflect the elimination of the domestic customer charge.

37. It is reasonable to change the percentage discount in Schedule No. DMS-2 so that it will reflect the estimated test year cost to Edison of providing comparable service to submetered tenants.

38. Edison's tariff schedules relating to streetlighting require rewording and rearrangement for purposes of improving their understandability.

39. It is not in the public interest to require Edison to provide a specific rate for low-pressure sodium-vapor lamps in its Schedule No. LS-2.

40. It is not in the public interest to close Schedule No. LS-2 to incandescent and mercury-vapor lamps.

41. The record in this proceeding does not provide an adequate basis for determining the relative merits of low-pressure and high-pressure sodium-vapor lamps.

42. It is not in the public interest at this time to require Edison to offer low-pressure sodium-vapor streetlighting service under its Schedule No. LS-1.

43. The historical methods for recovering expenditures on canceled and abandoned projects are adequate and equitable. The use of a forecasted test year amortization level, as proposed herein by Edison, has not been shown to be fair or necessary.

44. The evidence indicated that CWIP is assessed by the State Board of Equalization at or near HCLD; therefore, it is reasonable that CWIP be removed from expenses and capitalized on that basis.

45. Issues relative to the calculation of test year income tax expenses for ratemaking purposes can be more effectively explored and addressed in OII No. 24.

46. It is inappropriate, for purposes of this proceeding, to include in the adopted test year results of operations any costs related to Edison's Catalina utility operations.

47. For determining adopted test year expenses, it is reasonable to use a labor escalation factor of 9.5 percent for 1980 and a factor of 13.0 percent for 1981.

48. The jurisdistional cost allocation used in determining adopted test year results is reasonable for purposes of this proceeding and conforms to the evidence of record.

49. The increase in rates and charges authorized by this decision is justified and is reasonable; the present rates and charges, insofar as they differ from those prescribed by this decision, are for the future unjust and reasonable.

50. Specific goals for accomplishing market saturation of cost-effective conservation programs within a reasonable time frame are necessary for any effective conservation effort. Edison lacks a comprehensive statement of goals for achieving such market saturation. Therefore, we have established goals for Edison to meet within the 1981 test year.

51. Assessing a penalty to reduce rates by $5 million/year to reflect the "vigor, imagination and effectiveness "of Edison's conservation programs may be appropriate at the end of test year 1981. It is appropriate to base any assessment of the penalty for failure in the conservation area on Edison's recorded conservation achievement as reported in the December 31, 1981 report submitted to our Conservation Branch in addition to Edison's compliance with the required filings as described in the opinion.

52. Knowledge of the conservation potential for each class of customer is necessary to set realistic goals for conservation. Edison has not presently developed comprehensive analysis of conservation potential by class of customer.

53. Comparison of the cost of conservation programs with the marginal cost of energy is desirable to clearly demonstrate the savings associated with energy conservation. For an electric utility the marginal cost of energy includes some component of demand, although the marginal cost-effectiveness level will vary according to the time at which the saving occur. Edison relies on the electric cost equivalent to the average price of oil for determining conservation program cost-effectiveness.

54. Accurate measurement of the specific savings of individual programs and general savings of overall conservation efforts is crucial to the determination of cost-effectiveness. The accurate measurement of conservation requires a reasonable knowledge of energy savings persistence. Edison presently uses energy savings measurement techniques which are substantially limited in their ability to accurately describe the effect of Edison's conservation efforts. Edison has failed to complete a study of energy savings persistence.

55. It will promote the development of cogeneration if Edison undertakes the six cogeneration recommendations of the staff as recited in the opinion.

56. The petition for an award filed by TURN on March 28, 1980, and the appeal relating thereto filed by TURN on June 17, 1980 have no merit.

57. The petition filed on July 11, 1980 by CIEC for a proposed report has no merit.

58. The petition filed on July 17, 1980 by Air Products to present new testimony has no merit.

59. It is reasonable to require Edison to implement an energy conservation assistance program focusing on weatherization, refrigeration, and air conditioning in areas of extremely high summer temperatures.

60. A conservation contingency fund of $1,866,900 is reasonable for test year 1981 conservation programs.

B. CONCLUSIONS OF LAW

1. Edison should be authorized to file the revised electric rates which are set forth in Appendix B and which are designed to produce $294,196,000 in additional gross revenues based on the adopted test year 1981 results of operations.

2. Edison should be authorized and directed to make such other changes in its filed tariffs as are set forth in Appendix B.

3. Edison should be required to submit various conservation reports described in the opinion by the dates indicated therein.

4. Edison should be required to implement the PURPA regulatory standard for Information to Consumers.

5. The petition for award filed by TURN on March 28, 1980 and the appeal relating thereto filed by TURN on June 17, 1980 should be denied.

6. The petition filed on July 11, 1980 by CIEC for a proposed report should be denied.

7. The petition filed July 17, 1980 by Air Products to present new testimony should not be granted. Air Products may proceed in accordance with Decision No. 92169.

8. Edison should be required to undertake the staff-recommended cogeneration requirements described in the opinion.

9. The effective date of this order should be the date on which it is signed to meet applicant's need for immediate rate relief and to meet the requirements of the Regulatory Lag Plan.

O R D E R

IT IS ORDERED that:

1. Southern California Edison Company (Edison) is authorized and directed to file with this Commission revised tariff schedules for electric rates as set forth in Appendix B attached hereto and by this reference made a part hereof on or after the effective date of this order. The revised tariff schedules shall become effective on the date of filing, but not earlier than January 1, 1981, and shall comply with General Order No. 96-A. The revised rate schedules shall apply only to service rendered on or after the effective date hereof.

2. Edison shall submit by June 15, 1981, and annually thereafter, a statement of electric conservation potential for its service territory as described in the opinion.

3. Edison shall individually evaluate 1,000 distribution circuits for cost-effective Phase II capital improvements and report the results to the Commission by July 1, 1981. A similar report on the balance of its distribution circuits shall be submitted by December 31, 1981. These reports shall include aggressive plans for construction of all improvements found to be cost-effective. Edison shall continue to file quarterly reports with the Commission on its its Phase II CVR efforts.

4. By April 1, 1981, Edison shall submit its plan for implementation of its voltage surveillance program to individually monitor the maximum and minimum voltage received by customers on each of its distribution circuits. Edison shall have voltage surveillance in place on each of its circuits by December 31, 1981.

5. By October 15, 1981, and annually thereafter, Edison shall submit a statement of goals for achieving, by 1986, market saturation of all currently cost-effective conservation potential.

6. Edison shall expand its very small nonresidential audit program and develop ways to improve the results achieved by all nonresidential energy audits, giving consideration to the use of financial incentives where appropriate.

7. Edison shall submit data collection and measurement studies described in the text of the opinion by the dates indicated therein.

8. Edison shall make application for authority to provide financing assistance for cost-effective residential conservation measures.

9. Edison shall expand its cost-effectiveness guidelines, for conservation, to include the full marginal cost of electricity and submit a report on the guidelines to the Commission by June 30, 1981.

10. Edison shall develop and submit to the Commission a concise definition of its cost-effectiveness criteria for energy conservation programs by December 31, 1981.

11. Edison is authorized $39,000,000 for its conservation and load management programs as set forth in Table V-B.

12. Edison shall undertake the six staff-recommended cogeneration requirements described in the opinion.

13. Edison shall implement the PURPA regulatory standard for Information to Consumers.

14. Edison shall submit plans by January 31, 1981 for implementing a zero-interest financing conservation program. Edison is authorized to initially implement such a program for those portions of its service territory exposed to extremely high summer temperatures, and within the funding limitations authorized herein for the Residential Conservation Services and Conservation Contingency Fund.

Such programs shall be available to Edison's customers as soon as possible but not later than April 1, 1981. The Conservation Contingency Fund should not otherwise be used without prior authorization.

15. Edison shall obtain prior Commission concurrence or approval for any redirection of conservation and/or load management funds over $300,000 in a single year, and written staff approval signed by the Executive Director for any lesser amount exceeding either $100,000 or 10 percent of the authorized level of the program from which such funds would be taken.

16. The petition for award filed by Toward Utility Rate Normalization on March 28, 1980, and the appeal relating thereto filed by Toward Utility Rate Normalization on June 17, 1980 are denied.

17. The petition filed on July 11, 1980 by California Industrial Electric Consumers for a proposed report is denied.

18. The petition filed on July 17, 1980 by Air Products and Chemicals, Inc. to present new testimony is denied.

19. Within 180 days of the effective date of this order Edison shall file revised streetlighting schedules, restricting them in such a manner as to simplify them and improve their comprehensibility.

20. Edison shall cooperate with our staff and the affected customer groups in developing optional time of use rates and recommended modifications to demand charges for agricultural and general service customers.

21. Within 120 days of the effective date of this order, Edison shall file a report, as described in the opinion, assessing the cost and ratemaking treatment of spent nuclear fuel.

22. In its next general rate application and in any rate base offset procedure for San Onofre Nuclear Generating Station Units 2 and 3, Edison shall file a report assessing the cost of decommissioning Unit 1 of that generating station.

23. Edison is authorized an operational attrition allowance of $91,927,000 for 1982 and is authorized to file revised electric rates reflecting this allowance to be effective January 1, 1982. Except for domestic rates, all base rates will be increased across the board by a equal percentage of the 1981 base rates. The overall percentage increase to the domestic [illegible] revenues shall be the same as to other customer groups with a single-block base rate for lifeline and nonlifeline use.

24. Edison shall maintain a record of all base rate revenues for the six major customer groups.

25. Any base rate revenues for 1981 exceeding adopted revenues shall be refunded to ratepayers as directed by the Commission.

26. Edison shall file recorded 1982 results of operations, including earned return on equity, by March 1, 1983. Hearings to determine a course of action will be held if earned return on equity exceeds our adopted return on equity of 14.95 percent.

The effective date of this order is the date hereof.

Dated December 30, 1980, at San Francisco, California.

JOHN E. BRYSON
President
RICHARD D. GRAVELLE
CLAIRE T. DEDRICK
LEONARD M. GRIMES, JR.
Commissioners

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

APPENDIX A
Page 1 of 2

LIST OF APPEARANCES

Applicant: John R. Bury, David H. Barry, III, William E. Marx, Richard K. Durant, Carol B. Henningson, and Robert W. Kendall, Attorneys at Law, for Southern California Edison Company.

Protestants: Overton, Lyman & Prince, by John A. Payne, Jr. and Edward C. Rybka, Attorneys at Law, for Southwestern Portland Cement Company; V. Edward Duncan, for himself; and R. Dennis Hogle, for City of Oxnard.

Interested Parties: Graham & James, by Boris H. Lakusta, David J. Marchant, Thomas J. MacBride, Jr., and Byde W. Clawson, Attorneys at Law, for Western Mobilehome Association and California Hotel & Motel Association; John P. Terry, for City of Los Angeles, Department of Water and Power; McNees, Wallace & Nurick by Henry R. MacNicholas, Attorney at Law (Pennyslvania), for California Industrial Energy Consumers as follows: Airco, Inc., Armco, Inc., Ball Corporation, California Portland Cement Company, Champlin Petroleum Company, Crown Zellerbach Corporation, General Motors Corporation, Kaiser Cement Corporation, Kaiser Steel Corporation, Kimberly-Clark Corporation, Mobil Oil Corporation, Monolith Portland Cement Company, Monsanto Company, Riverside Cement Company, Soule Steel Company, Southwestern Portland Cement Company, Stauffer Chemical Company, PPG Industries, Texaco, Thatcher Glass Manufacturing Company, and Union Carbide Corporation; Grant Nelson, for Metropolitan Water District of Southern California; Downey, Brand, Seymour & Rohwer, by Richard R. Gray and Philip A. Stohr, Attorneys at Law, for General Motors Corporation; Brobeck, Phleger & Harrison, By Gordon E. Davis and William H. Booth, Attorneys at Law, for California Manufacturers Association; William L. Knecht, for California Association of Utility Shareholders; Glen J. Sullivan, Attorney at Law, for California Farm Bureau Federation; Jimmy Lucas, for the City of Carson; Dave Rees, for City of Simi Valley; Michael J. Barrett, for NETWORK; Judie Kesson, for City of Ventura; James F. Sorensen, for Friant Water Users Association; Stephen A. Edwards, Jeffrey Lee Guttero, and William L. Reed, Attorneys at Law, for San Diego Gas & Electric Company; Norman Elliott, Attorney at Law, for Air Products Company; Kenneth A. Strassner, Attorney at Law (Washington, D.C.), for Kimberly-Clark Corporation; Hastings, Blanchard, Weiler & Kennedy, by Peter T. Kennedy, Attorney at Law, for Christian Science Churches; and Greggory Wheatland, Attorney at Law, for California Energy Resources Conservation and Development Commission.

Commission Staff: Timothy E. Treacy, and Freda Abbott, Attorneys at Law, Kenneth Kindblad, and Bruce M. DeBerry.

Authorized Tariffs

Schedule No. A-7

Demand Charge:	Per Meter Per Month
First 200 kW or less of billing demand	$860.00
All excess kW of billing demand, per kW	4.30

(Subject to minimum demand charge.
See Special Condition No. 5)

Energy Charge (to be added to Demand Charge):

All kWh, per kWh	1.160¢

Special conditions No. 10, Adjustment for on-peak demand shall be eliminated.

Schedule No. D

	Per Meter Per Month	
	Lifeline Service	Other Domestic Service
Base rate charges:		
First 240 kWh, per kWh	3.480¢	3.480¢
Excess kWh, per kWh	2.410¢	3.480¢

Schedule No. DMS-1

The Lifeline Discount shall be 33%.

Schedule No. DMS-2

The Lifeline Discount shall be 45%

Schedule No. DWL

Lamp Charge:	Per Meter Per Month
75 watt mercury vapor lamp, per lamp	$ 5.70
Minimum Charge:	
Per customer	$100.00

Schedule No. GS-1

	Per Meter Per Month
Service Charge	$4.50
Energy Charge (to be added to Customer Charge	
All kWh, per kWH	4.580¢

Schedule No. GS-2

	Per Meter Per Month
Demand Charge:	
First 20 kW or less of billing demand	$76.00
All excess kW of billing demand, per kW	3.80
(Subject to minimum demand charge. See Special Condition No. 5)	
Energy Charge (to be added to Demand Charge):	
All kWh, per kWh	1.380¢

Schedule No. P-1

This schedule shall be eliminated, and customers shall be transferred to Schedule GS-1 or any other otherwise applicable rate schedules.

Schedule No. PA-1

	Per Meter Per Month
Service Charge:	
Two horsepower and over of connected load, per horsepower	$1.00
Energy Charge (to be added to Service Charge):	
All kWh, per kWh	2.020¢

Special Conditions:

Off-Peak Credit: The off-peak credit shall be $.50 per horsepower of connected load per month.

The other changes to the special conditions, as proposed by Edison, shall be made.

Schedule No. TOU-PA-1

Monthly Service Charge (Per Meter)
Customer Charge of $4.20 plus $1.50 per kVA of Transformer Capacity

Monthly Energy Charges:

On-peak kWh	2.840¢
Off-peak kWh	0.200¢

Special Conditions: The changes to the Special Conditions, as proposed by Edison, shall be made.

Schedule No. PA-2	Per Meter Per Month
Demand Charge:	
First 75 kW or less of billing demand	$281.25
All excess kW of billing demand, per kW	3.75
(Subject to minimum demand charge. See Special Condition No. 5)	
Energy Charges (to be added to Demand Charge):	
All kWh per kWh	1.120¢

Schedule No. TC-1	Per Meter Per Month
Customer Charge	$4.00
Energy Charge (To be added to Customer Charge):	
All kWh, per kWh	2.520¢

Schedule No. TOU-8

Applicability

Applicable to general service, including lighting and power.

This schedule is mandatory to all customers whose monthly maximum demand exceeds 500 kW for any three months during the preceding 12 months. Any customer whose monthly maximum demand has fallen below 450 kW for 12 consecutive months may elect to take service on any other applicable schedule.

	Per Meter Per Month
Customer Charge	$560.00
Demand Charge (to be added to Customer Charge):	
All kW of on-peak billind demand, per kW	$ 5.05
Plus all kW of mid-peak billing demand, per kW	0.65
Plus all kW of off-peak billing demand, per kW	No Charge
(Subject to minimum demand charge. See Special Condition No. 6)	
Energy Charge (to be added to Demand Charge):	
All on-peak kWh, per kWh	1.266¢
Plus all mid-peak kWh, per kWh	0.929¢
Plus all off-peak kWh, per kWh	0.593¢

Special Conditions:

The changes to the special conditions as proposed by Edison shall be made.

Those individual customers who are to be transferred to this schedule as a result of Decision No. 92549, shall be transferred to Schedule No. TOU-8 on the date of the reading of the customer's meter immediately subsequent to such customer being notified as to his eligibility to receive service on Schedule No. TOU-8.

Schedule No. OL-1

Luminaire Charge:

Lamp Size — Lumens	All Night Service Per Lamp Per Month	Energy Curtailment Service: Midnight Equivalent Service Per Lamp Per Month	Energy Curtailment Service: Facilities Charge Per Lamp Per Month
Mercury Vapor Lamps*			
7,000 Lumens	$6.35	$5.90	$5.15
20,000 Lumens	8.35	7.40	6.10
High Pressure Sodium Vapor Lamps			
5,800 Lumens	$6.45	$6.30	$5.40
9,500 Lumens	6.80	6.55	5.55
22,000 Lumens	8.10	7.60	6.40

Pole Charge (to be added to Luminaire Charge):	Per Pole Per Month
For each additional new wood pole installed	$2.95

*Closed to new installations as of February 1, 1980.

Schedule No. LS-1

	All Night Service	Energy Curtailment Service	
		Midnight or Equivalent Service	Facilities Charge
Lamp Size — Lumens	Per Lamp Per Month	Per Lamp Per Month	Per Lamp Per Month
Incandescent Lamps*			
1,000 Lumens	$3.45	$3.25	$2.30
2,500 Lumens	4.60	4.15	3.05
4,000 Lumens	5.35	4.25	2.85
6,000 Lumens	6.40	4.80	3.05
10,000 Lumens	8.45	5.75	3.35
Mercury Vapor Lamps*			
3,500 Lumens	$5.95	$5.70	$5.10
7,000 Lumens	6.30	5.85	5.10
11,000 Lumens	7.30	6.70	5.75
20,000 Lumens	8.30	7.35	6.05
35,000 Lumens	10.65	8.60	6.40
55,000 Lumens	12.30	9.40	6.45
High Pressure Sodium Vapor Lamps			
3,300 Lumens	$6.20	$6.05	$5.25
5,800 Lumens	6.40	6.25	5.35
9,500 Lumens	6.75	6.50	5.50
16,000 Lumens	7.50	7.10	6.00
22,000 Lumens	8.05	7.55	6.35
25,500 Lumens	8.40	7.75	6.40
47,000 Lumens	9.45	8.40	6.70

* Closed to new installations.

Schedule No. LS-2

	Per Month			
	All Night Service		Midnight Service	
	Multiple	Series	Multiple	Series
RATE A — UNMETERED SERVICE:				
For each kW of lamp load, per kW	$9.10	$11.85	$6.60	$7.30

RATE B — METERED SERVICE:

	Per Meter Per Month
Meter Charge:	
Multiple Service	$ 4.50
Series Service	12.00
Energy Charge (to be added to Meter Charge):	
All kWh, per kWh	2.566¢

RATE C — MAINTENANCE SERVICE — OPTIONAL:
In addition to the Rate A and Rate B charges

Lamp Rating		Per Lamp Per Month
Incandescent Lamps - Extended Service*		
1,000	Lumens	$0.74
2,500	Lumens	0.71
4,000	Lumens	0.74
6,000	Lumens	0.78
10,000	Lumens	0.82
Mercury Vapor Lamps*		
3,500	Lumens	0.31
7,000	Lumens	0.28
11,000	Lumens	0.36
20,000	Lumens	0.31
35,000	Lumens	0.54
55,000	Lumens	0.48
High Pressure Sodium Vapor Lamps		
3,300	Lumens	0.70
5,800	Lumens	0.70
9,500	Lumens	0.70
16,000	Lumens	0.71
22,000	Lumens	0.70
25,500	Lumens	0.71
47,000	Lumens	0.74

* Closed to new installations as of September 15, 1980, and to all existing installations as of January 1, 1982.

Change Rule No. 9:

RENDERING AND PAYMENT OF BILLS

A. Rendering of Bills.

4. The Company reserves the right to accumulate bills until the total amount due exceeds $2.00.

ATTACHMENT FOR ITEM NO. 5.c

RATE DEVELOPMENTS

Granted

	Electric	Gas	Steam
Test Year utilized	1981	1981	n/a
Annual amount of revenue increase requested-test year basis (000's)	$126,630.0	$18,280.0	n/a
Date petition filed	7/1/80	7/1/80	n/a
Annual amount of revenue increase allowed-test year basis (000's)	$ 80,943.5	$14,957.9	n/a
Percent increase in revenues allowed*	28.31%	26.59%	n/a
Date of final order	12/30/80	12/30/80	n/a
Effective date	1/3/81	1/3/81	n/a
Rate base finding (000's)	$1,095,299.0	$159,086.1	n/a
Construction work in progress included in Rate base (000's)	0	0	n/a
Rate of return on rate base authorized	11.36%	11.36%	n/a
Rate of return on common equity authorized	14.50%	14.50%	n/a

Revenue Effect (000's)

	Electric	Gas	Steam
Amount received in year granted **	$80,943.5	$14,957.9	n/a
Amount received in subsequent year (If not available, annualize amounts received in year granted)	n/a	n/a	n/a

Pending Requests

	Electric	Gas	Steam
Test year utilized	1982	1982	1982
Amount (000's)	$197,775.0	$24,990.0	$1,768.0
Percent increase*	55.60%	38.86%	9.41%
Date petition filed	12/22/80	12/22/80	12/22/80
Date by which decision must be issued	12/31/81	12/31/81	12/31/81
Date of return on rate base requested	13.90%	13.90%	13.90%
Rate of return on common equity requested	19.00%	19.00%	19.00%
Amount of rate base requested	$1,213,817.0	$171,765.0	$456.0
Amount of construction work in progress requested for inclusion in rate base	$6,385.0	n/a	n/a

* % change in base rates

** Estimated revenue based on projected sales