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Decision 87-12-066 December 22, 1987

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. (Electric) (U 338 E)	Application 86-12-047 (Filed December 26, 1986)
Order Instituting Investigation into the rates, charges, and practices of the Southern California Edison Company	I.87-01-017 (Filed January 14, 1987)

(Appearances are listed in Appendix J.)

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INTERIM OPINION

I. Summary of Decision

This decision orders Southern California Edison Company (Edison) to reduce its base revenues by $48.5 million or 0.9% and authorizes Edison to increase its major additions adjustment clause (MAAC) by $73.7 million or 1.4 percent. These rate changes, which are to become effective January 1, 1988, will result in an increase of $1.82 or 4.4% per month for a typical residential customer using 500 kWh per month.

In approving the increase in MAAC rates a special procedure is established to review the reasonableness of Edison's expenditures for capital projects costing over $50.0 million. Through this procedure Edison will be allowed to increase rates by an amount equal to 75% of a project's revenue requirement, subject to refund.

Additionally, a return on common equity (ROE) of 12.75% is authorized, $80.0 million is adopted as a ratemaking cost cap for Edison's Sylmar-Pacific Northwest intertie expansion project (DC Expansion), Edison's electric vehicle program is not funded, increased funding for an expanded female/minority business enterprises (F/MBE) program is authorized, guidelines for evaluating plant held for future use (PHFU) are adopted and a procedure is created for funding Edison's hazardous waste management program. The significant reductions in Edison's requested revenue requirement are listed below.

Major Revenue Requirement Reductions
(Dollars in millions)

	Amount
Return on Equity	$ 47.6
Additional Productivity	25.6
Steam Production Accounts: 512 & 513	16.0
A & G	
Customer Growth	3.2
Medical	4.3
Insurance	1.8
Nuclear Fuel	9.3
Demand Side Management	6.3
Nuclear Production	4.3
Distribution	4.0
Coal Inventory	1.8
Plant Held for Future Use	1.1
Customer Accounts	0.5
Miscellaneous	1.7
Total	$127.5

By this decision, the Commission continues its commitment to marginal cost ratemaking. Marginal energy, demand, distribution, and customer costs are adopted and used in the revenue allocation process. Additionally, avoided energy and capacity costs are adopted for use in developing prices for power purchased by Edison from qualifying facilities.

Revenue allocation is based on an Equal Percent of Marginal Cost methodology aimed at achieving cost-based rates, providing accurate price signals related to energy consumption, and discouraging uneconomic bypass of the Edison system by customers with the potential to generate their own power. A cap on the revenue increases to customer classes and rate groups, however, is adopted for the test year set at 5% over the system average percentage change. This cap is necessary to mitigate the adverse rate impacts for certain customer groups which would result from moving to a full EPMC revenue allocation for 1988.

background sections are in 1988 dollars and California Public Utilities Commission (CPUC) jurisdictional. Attached to this decision are tables setting forth the adopted revenue requirement and rate design. The adopted summary of earnings is shown on page 30 of Appendix C. Included as the final attachment is a list of acronyms to assist the reader.

Typically, general rate cases for utilities the size of Edison are long and difficult. While we have come to expect this, two items have made this proceeding even more trying than previous Edison general rate cases. First, to comply with Public Utilities Code (PU) Section 311, which requires the release of Administrative Law Judge (ALJ) proposed decisions at least 30 days prior to issuance of the Commission's decision, the rate case schedule was shortened. This resulted in multiple briefing dates and a condensed hearing schedule. Second, the parties have intensified their participation in the areas of marginal cost, rate design, and resource planning. Because of these changes we have issued Order Instituting Rulemaking (R.) 87-11-012 to consider modifications to the current rate case plan.

Finally, although the sailing was often rough, we wish to thank the interested parties, PSD, and Edison for their cooperation in guiding this rate case through the uncharted waters of PU Section 311.

III. Procedural Background

On December 26, 1986, Edison filed Application (A.) 86-12-047 requesting authority to increase base rate revenues by $301.5 million or 5.4% for test year 1988. Edison also requested attrition increases for 1989 and 1990. Since the filing of

CORRECTION

THIS DOCUMENT HAS

BEEN REPHOTOGRAPHED

TO ASSURE

LEGIBILITY

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Revenue allocation is based on an Equal Percent of Marginal Cost methodology aimed at achieving cost-based rates, providing accurate price signals related to energy consumption, and discouraging uneconomic bypass of the Edison system by customers with the potential to generate their own power. A cap on the revenue increases to customer classes and rate groups, however, is adopted for the test year set at 5% over the system average percentage change. This cap is necessary to mitigate the adverse rate impacts for certain customer groups which would result from moving to a full EPMC revenue allocation for 1988.

The rate structures adopted for each customer group and for each schedule within those groups are based on current Commission rate design policies. The adopted rate structures therefore reflect, to the extent possible and practical, cost-based rates designed to provide accurate and understandable price signals to which the customer can respond, to reflect a customer's usage patterns and characteristics, to recover the customer group's revenue requirement, and to mitigate any negative bill impacts.

II. Introduction

This decision is the culmination of a fourteen month process which began in September 1986 with Edison's tendered Notice of Intent (NOI). The decision is divided into three major sections:

1. Results of Operation - traditional revenue requirement items, such as operating expenses, taxes, depreciation, and plant.

2. Major Issues - policy issues which affect Edison's revenue requirement including; cost of capital, resource planning, research, design and development (RD&D), productivity, employee compensation, F/MBE, affiliate transactions, hazardous waste, and demand side management.

3. Rates - issues associated with how Edison's revenue requirement should be recovered and payments to qualified facilities (QFs). This section is divided into five categories: marginal cost, revenue allocation, rate design, bypass, and cogeneration.

With the exception of the summary of the decision and procedural background sections, all dollars in this decision are on a total company basis and in 1985 dollars, unless otherwise noted. Dollars referenced in the summary of decision and procedural background sections are in 1988 dollars and California Public Utilities Commission (CPUC) jurisdictional. Attached to this decision are tables setting forth the adopted revenue requirement and rate design. The adopted summary of earnings is shown on page 30 of Appendix C. Included as the final attachment is a list of acronyms to assist the reader.

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Finally, although the sailing was often rough, we wish to thank the interested parties, PSD, and Edison for their cooperation in guiding this rate case through the uncharted waters of PU Section 311.

III. Procedural Background

On December 26, 1986, Edison filed Application (A.) 86-12-047 requesting authority to increase base rate revenues by $301.5 million or 5.4% for test year 1988. Edison also requested attrition increases for 1989 and 1990. Since the filing of

A.86-12-047, Edison has made considerable revisions and currently is requesting an increase of $79.0[1] million or 1.5 percent.[1]

The major causes for the reduction in Edison's request were the removal from base rates of $79 million in revenue requirement associated with three large plant additions: Balsam Meadows hydroelectric generation plant, Devers-Valley-Serrano transmission line, and DC Expansion, a reduction in the requested return on equity and a change in the capital structure, $67 million, and lower depreciation rates, $96 million.

On February 2, 1987, a prehearing conference was held in Los Angeles to discuss procedural matters including a modified rate case schedule to reflect the requirements of PU Section 311. Additionally, five days of public hearings, a Commission en banc public hearing in Pomona, 53 days of evidentiary hearings, and Commission en banc oral arguments were held. During the course of this proceeding 55 public witnesses made statements, 96 expert witnesses testified, and 317 exhibits were received.

An Order Instituting Investigation (I.) 87-01-017 into the rate changes and practices of Edison was issued on January 14, 1987. This order serves as the procedural vehicle for considering a reduction in Edison's rates and was consolidated with A.86-12-047.

In accordance with PU Section 311 the ALJs' draft decision, prepared by ALJs Sara S. Meyers and Francis S. Ferraro, was issued on November 20, 1987. Comments on the proposed decision in this proceeding were filed by the following parties: Edison, PSD, Institute, Public Advocates, FEA, TURN, CMA, CCC, CSC, IU,

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1 This decision increases Edison's request to reflect the exclusion of $19.4 million of CLMAC revenues from present rate revenues. Further details are provided in the section, Revenues at Present Rates.

CLECA/CSPG, PG&E, SDG&E, WMA, RV Park Owners, Farm Bureau, and ACWA.

These comments have been reviewed and carefully considered by the Commission. Any changes required by the comments have been incorporated in this final decision.

IV. Results of Operations

A. Escalation

1. Labor

Edison and Public Staff Division (PSD) are in agreement as to the labor escalation rates to be used to escalate nominal dollars into constant dollars and to forecast wage and salary increases for operation and maintenance expense. The labor escalation rates for the years through 1988 are to be based on Edison's actual negotiated union contract agreements, adjusted to reflect the effective date of the agreements. The labor escalation rates for the years 1989 and 1990 are to be determined in Edison's attrition filings by the prior years percentage change in the Consumer Price Index-Wage Earners. For this decision we will adopt the agreed upon labor escalation rate of 3.5% for both 1987 and 1988.

2. Non-Labor

Edison and PSD are in agreement regarding the methodology to be used in developing non-labor escalation rates in deriving the test year's and attrition years' expenses. This methodology uses Data Resources, Incorporated's (DRI) forecast of 25 material and labor price indexes and a gross national product deflator index to develop utility specific non-labor escalation rates. We will adopt Edison's and PSD's recommended non-labor escalation rates of 2.99% for 1987 and 4.41% for 1988.

Sales And Revenue

3. Sales Forecast

Edison and PSD are in agreement with respect to the forecast of kilowatt-hour (kWh) sales. We will adopt their forecasted 1988 kWh sales as shown below:

Summary of Kilowatt-Hour Sales
(Millions of kWh)

Class of Service	Adopted 1988
Residential	19,832
Agricultural & Pumping	2,077
Small & Medium Power	21,798
Large Power	20,351
Streetlighting	471
Resale	850
Net Edison	65,379
Resale - Special Contracts	580
Total	65,959

4. Revenue at Present Rates

The present rate revenues calculated by Edison for the 1988 test year were developed from the base rate levels in effect at the time this filing was prepared. PSD is in agreement with Edison's present rate revenues as derived from the sales forecast previously discussed. A review of these revenues indicates that the conservation/load management adjustment clause (CLMAC) revenues are included in present revenues.

The CLMAC revenues are design to recover prior years' conservation and load management expenses and are not adjusted by this decision. As such, it is inappropriate to include CLMAC revenues in this decision's adopted present revenues. While this has no affect on the adopted revenue requirement it does increase the difference between present and adopted base rate revenues by $19.4 million. We will adopt Edison's present rate revenues excluding CLMAC revenues. The adopted present rate revenues are shown in Appendix C.

5. Other Operating Revenue

Other operating revenues are revenues obtained by a utility from other than the sale of electric energy. Other operating revenues include return check charge, service establishment charges, transmission of electricity for others, joint pole rentals, added facilities revenues, and miscellaneous revenues.

PSD agreed with Edison's original estimate of other operating revenues. However, PSD proposed the addition of certain revenues pertaining to the gains on property sold, timber sales, and subsidiary operations. The issue of subsidiary revenues is addressed in the section on affiliate transactions.

PSD's recommendation on gains from property sold involves three distinct proposals. PSD's first proposal involves the inclusion of an estimate for account 411 (gains/losses on the disposition of utility property) in the test year to reflect future gains or losses on property held for future use. PSD utilized a five-year historical average in determining the estimated 1988 revenue level for account 411.

PSD's second proposal is to include an estimate for revenues derived from properties sold from account 121 (non-utility property) that were originally in account 105. PSD recommends that these revenues should be recorded in account 411, an above-the-line revenue account for test year 1988. PSD proposed a two-year historical average in determining the 1988 estimated revenue for this item.

PSD's third proposal relating to gains or losses on the sale of utility plant involves property sold directly out of account 101 (electric plant-in-service) and account 103 (experimental electric plant unclassified). PSD recommends that revenues derived from property sold directly out of these accounts at any time during their useful life should go directly to the ratepayer. The gain or loss on property originally in accounts 101 or 103 and transferred to account 121 prior to sale should be allocated between the shareholder and ratepayer based upon the time it was in rate base and in non-utility property. PSD again proposed a two-year average in determining the 1988 estimated revenue for this item.

The last item PSD proposed for inclusion in other operating revenues is revenues derived from timber sales. PSD proposes the use of a five-year historical average in determining the estimated 1988 timber revenue.

Edison agrees with PSD that revenues associated with gains or losses from property sold and timber sales should be included in the 1988 test year. However, Edison believes that the test year estimates should be based upon a five-year historical average so that all of PSD's proposals are consistent. PSD has agreed with Edison's proposal.

Based upon a five-year average for each of the above items, Edison increased its estimate of other operating revenues for test year 1988 by $2.4 million.

B. Production Expenses

Production expenses are all costs, excluding fuel, associated with generating electricity. These expenses include the cost of operating and maintaining Edison's electric generation facilities.

1. Steam Production Expense

Steam production expenses represent the cost, excluding fuel, of operating and maintaining Edison's fossil fuel electric generation units. Edison requests $209.2 million for steam production expenses in test year 1988. PSD recommends that Edison's request be reduced by $3.1 million for three specific projects and an additional $5.9 million in the area of overhaul expense.

To estimate steam production expense, Edison collected seven years of recorded expenses (1979-1985), by Federal Energy Regulatory Commission (FERC) account. Adjustments were applied to remove unusual activities or items of expense that were not appropriate for estimating based on recorded data. The recorded data, after adjustments, was escalated to constant 1985 dollars and trended using a linear least-squares analysis on a labor, non-labor basis by account. Trended results that met one of the generally accepted statistical measures of a coefficient of determination, R^2, of .60 and greater or a T-statistic of 2 or greater were retained if judgment also indicated that the circumstances that caused the trend in the recorded data would continue into the estimated period. Trends not meeting these measures were discarded and in most cases a seven-year historical average was substituted.

Future year adjustments such as those removed from the recorded years were estimated in 1985 dollars and added to the trended/averaged amounts in the years in which they are expected to occur. The total of the adjustments and the trended/averaged portion were escalated as appropriate resulting in the estimated amounts for 1986-1988.

PSD followed Edison's estimating methodology with the exception of four specific adjustments. As part of the examination process, PSD made a detailed on-site field review of overhaul work scopes and specific adjustments with most generating station management and engineering staffs. Additionally, PSD reviewed accounting and administrative practices and reviewed the application and workpapers.

The remaining issues between Edison and PSD involve: (1) proposed modification of 480 MW boilers for minimum load operation, (2) proposed modification of 215 MW units to permit two-shifting, (3) research, development and demonstration expenses, and (4) level of overhaul expenses. An additional issue was raised by Federal Executive Agencies (FEA). FEA asserts that Edison should not fully recover expenses for abnormal/non-recurring maintenance for turbine rotor repairs. This issue amounts to a test year reduction of $4.4 million. A complete discussion of the boiler modifications and RD&D expenses is contained in the resource plan and the RD&D section, respectively. The remaining issues are discussed in the following sections and detailed in the table below:

Steam Production Expense
(1985 Dollars)

Issue	Edison	PSD	FEA	Adopted
		(Dollars in Thousands)		
Adjustments:				
Overhaul Expense	$40,680	$34,817	$ -	$34,817
Abnormal/Non-Recurring Maintenance	5,947	-	1,501	1,982

2. Overhaul Expense

PSD recommends that Edison's forecasted expenditures for steam generation unit overhauls be reduced by $5.9 million. PSD states that Edison proposes to increase accounts 512 and 513 by over 50% due to the development of new criteria to schedule steam generating unit overhauls. While these new criteria are intended to reduce the number and duration of overhaul outages, PSD argues that Edison has not demonstrated how these reductions relate to savings of forecasted O&M expense. To recognize the yearly fluctuations in overhaul activities, PSD recommends a seven-year average (1979-1985) of overhaul expense be used to for test year 1988.

We agree with PSD that Edison has neglected to fully justify a sizable increase in overhaul expense. Edison states that it expects the new overhaul criteria to reduce routine activities during every overhaul, but fails to quantify this benefit. Without adequate justification, such as a cost-effectiveness analysis, we will average overhaul expense. Consistent with the averaging methodology used for other steam production expense estimates, we find PSD's use of a seven-year average of recorded overhaul expense appropriate. We will adopt a seven-year average of recorded overhaul expense and reduce Edison's requested steam production expense by $5.9 million.

3. Abnormal/Non-Recurring Maintenance

FEA contends that repairs planned for the low pressure turbine rotor during Redondo generating station unit 7's next overhaul are abnormal/non-recurring maintenance and the expense should not be fully recovered in the test year. FEA recommends the expense be recovered over a fifteen-year period. Although turbine repairs of this magnitude are not done on any one unit on a routine annual basis, Edison states that they are a normal expected activity on a cyclic basis. As Edison's witness testified:

> "...this type of work is planned for all the units in this class in subsequent years..."

While FEA's proposal only recognizes the funding requirement for one unit every 15 years, Edison's request assumes this type of repair will occur annually.

We believe that neither of these approaches yields an appropriate expense level for test year 1988. We consider three years to be representative of the frequency of this type of repair and will reduce Edison's request by $4.0 million to reflect this.

4. Hydraulic Production Expense

Edison's original estimate of hydro production expense was $20.9 million. Reductions by Edison have lowered this amount to $20.5 million.

Both Edison and PSD recommend that $20.5 million be adopted for test year hydro production expense. We will adopt their recommendation.

5. Other Production Expense

Edison's original estimate for other production expense was $29.5 million. Reductions by Edison and the transfer of $10.0 million for hazardous waste management costs to a subsequent proceeding have lowered this amount to $17.2 million.

Both Edison and PSD recommend that $17.2 million be adopted for test year other production expense. We will adopt their agreed upon estimate.

6. Nuclear Power Production Expense

Edison and PSD are in agreement with respect to the test year 1988 level of operation and maintenance (O&M) expense for the San Onfre nuclear generating station units (SONGS). Edison and PSD are also in agreement that an increase in Nuclear Regulatory Commission (NRC) fees should receive rate relief for test year 1988 if it is enacted by legislation during this proceeding. If legislation is enacted subsequent to this proceeding, both Edison and PSD consider rate relief through the attrition mechanism appropriate. Since legislation has not been enacted, we will allow Edison to seek rate relief for increased NRC fees through its attrition mechanism. Finally, Edison, PSD, and FEA are in agreement with the continuation of the flexible refueling mechanism adopted in Edison's last general rate case for use with SONGS and Palo Verde nuclear plant refuelings.

Although PSD agrees with Edison's SONGS O&M expense estimates, it recommends a $2.3 million reduction in Edison's O&M expense level for Palo Verde nuclear generating station units (Palo Verde), including refueling. While this decision only authorizes O&M and refueling expenses for Palo Verde 1 and 2, O&M and refueling expenses were also addressed for Palo Verde 3. To avoid relitigating this issue Edison should, when Palo Verde becomes commercially operational, reflect the level of O&M and refueling expenses found reasonable in this decision. Edison's A.87-08-054 is the appropriate proceeding in which to address the implementation of rate changes associated with Palo Verde 3 O&M and refueling expenses. Additionally, FEA takes exception to Edison's O&M estimate with regard to two items totaling $5.9 million.

Each of the issues and their dollar impact on test year 1988 are identified in the following table:

Nuclear Power Production Expense Issues

Issue	Edison	FEA	PSD	Adopted
		(Dollars in Thousands)		
SONGS 3 Steam Generator Chemical Cleaning	$ 4,884	$ 0	$ -	$ 1,628
SONGS 1 Spent Nuclear Fuel	970	0	-	0
Palo Verde Refueling Outage	3,960	0	2,772	3,960
Palo Verde O&M Expense	18,464	-	17,379	18,464

Edison developed its revised estimate of nuclear production expense for SONGS 1, 2 and 3 using recorded O&M expense data for the years 1984-1986. Historical adjustments were applied to the recorded O&M expense data for each year to remove unusual, one-time, or cyclical expenses. The resulting average-year expenses were adjusted for expenses expected to occur in future years. These future-year adjustments included reductions in expense because of several identified productivity measures. Refueling outages were specifically identified for each year by unit rather than normalized because of Edison's request to have a flexible refueling outage schedule during the test and attrition-year period of 1988-1990.

For Palo Verde 1, 2 and 3, Edison utilized the zero-base O&M expense estimates provided by Arizona Nuclear Power Project (ANPP). With the sole exception of the addition of new NRC fees (imposed on all nuclear units) not included in ANPP's estimate, Edison accepted ANPP's total O&M expense estimate as reasonable, but concluded that the base O&M and refueling outage expense needed adjustment. Without changing ANPP's total O&M expense estimate, Edison scaled-up the refueling outage expense estimates provided by ANPP to reflect 70-day refueling outages rather than the 49-day refueling outages assumed in the expense estimate. Since the total O&M expense does not change, scaling-up refueling outage expense results in a lower anticipated base level O&M expense.

PSD recommends that the level of O&M expenses for Palo Verde be determined from the 1985 average O&M expenses for 24 large nuclear units. This estimating methodology is proposed by PSD because Palo Verde 1 and 2 have recently gone into commercial operation and as a result there is an absence of operating history for developing ratemaking estimates. In support of this approach PSD states that the initial ratemaking O&M expense estimates for SONGS 2 and 3 were developed from an average of other nuclear units. Finally, PSD points out that SONGS 2 and 3 O&M expenses in the early years were well in excess of the average of other nuclear units, but after approximately two years of operation Edison was able to reduce O&M expenses below the average. Since Palo Verde 1 and 2 are approaching two years of operation, PSD believes that they should follow the pattern of SONGS and approach the national average for O&M expenses.

Edison is opposed to PSD's averaging methodology for determining the Palo Verde O&M expense level. Edison states that the comparative study used by PSD is not precise, does not consider the fundamental differences which exist among nuclear plants, and is only useful to establish a zone of reasonableness. Additionally, Edison argues that the comparative study used by PSD shows that O&M expenses varied by at least $20 million above or below the average and were 11.8% higher in 1986.

For the costs associated with Palo Verde refueling outages PSD recommends that ANPP's estimate based on 49-day outages be used in place of Edison's proposed 70-day outages. This results in a $1.2 million reduction in Edison's requested outage costs. Edison responds by stating that ANPP revised its outage duration estimate to 70-80 days and that Edison's use of 70 days reflects its experience at SONGS 2 and 3.

Because of the lack of recorded data from which to judge the reasonableness of Edison's O&M expense level for Palo Verde, PSD proposes that an average O&M expense level for other nuclear units be used. Although PSD's approach is conceptually valid, its application is flawed.

First, PSD's average does not take into consideration geographical differences among units. Second, refueling expenses were not excluded. Third, PSD did not attempt to reconcile the sizable difference between 1985 and 1986 average O&M expenses. In contrast the ANPP managers and supervisors prepared a detailed zero-based budget in which Edison was a participant, PSD reviewed ANPP's budget and had no specific adjustments, and Edison reduced its share of ANPP's budgeted O&M expenses by $1.2 million.

Because of the detailed analysis and review process used to develop and judge ANPP's estimates, we find Edison's O&M expense estimates for Palo Verde reasonable. However, we also agree with Edison that PSD's comparative analysis is useful to establish a zone of reasonableness. We expect Edison to include in its next general rate application a comparative study that can be used for that purpose. With respect to Edison's refueling outage expense estimate, we consider Edison's use of 70-day outages a reasonable approximation for ratemaking based on recorded experience at SONGS 2 and 3.

FEA recommends that chemical cleaning costs totaling $4.9 million for SONGS 3 be disallowed and $2.9 million for SONGS 1 spent nuclear fuel reprocessing be excluded from rates. These adjustments would reduce Edison's request for test year 1988 by $5.9 million.

Edison states that the chemical cleaning process will be performed in conjunction with the replacement of feedwater heaters with new components that do not contain copper-bearing material. FEA cites Edison's testimony which claims this is a one-time expense which does not represent a normal refueling outage activity. As a result FEA recommends the entire amount be excluded from rates. Edison argues that this expense is included in its estimate of refueling outage expense and as such is part of the mechanism which allows for a flexible refueling schedule. Finally, while Edison agrees that this is a one-time expense for SONGS 3, it also plans to clean SONGS 2 in 1990.

The fact that this is a one-time expense does not preclude Edison from recovering its cost. We are satisfied with Edison's justification for cleaning the steam generators to mitigate the effects of copper contamination. However, because this is a one-time expense we will allow Edison to recover this cost over the rate case cycle of three years. Additionally, we will modify the ALJs' draft decision to allow Edison to include a similar expense for the SONGS 2 chemical cleaning in its attrition filing for 1990.

Edison also included an adjustment for test year 1988 to cover the planned write-off to expense of one-third of the costs derived from a contractual agreement with General Electric Company. This contract was for the reprocessing of SONGS 1 spent nuclear fuel leased from the Atomic Energy Commission. FEA takes the position that the recovery of this expense which was incurred from 1976 through 1983 is retroactive ratemaking and should be disallowed.

Edison states that the Nuclear Waste Policy Act enacted into law in January 1983 made it necessary for Edison to analyze its accounts which contained spent nuclear fuel costs. As a consequence of Edison's evaluation of those accounts, the cost associated with the reprocessing agreement were identified as appropriate for write-off to expense in October 1986. This general rate case is the first opportunity for Edison to seek rate recovery for that expense. Finally, Edison claims that a similar write-off of spent nuclear plutonium salvage costs was allowed in test year 1983.

We agree with FEA that recovery of expenses previously incurred without our prior approval of a mechanism for tracking these costs for later recovery is retroactive ratemaking. Edison claims that it was afforded similar ratemaking treatment in its test year 1983 rate case. However, our review of Edison's 1983 general rate case decision, Decision (D.) 82-12-055, indicates that Edison was only allowed to recover projected expenses associated with permanent disposal of spent nuclear fuel. We will disallow Edison's request for $2.9 million in spent nuclear fuel costs amortized over three years.

Finally, SDG&E owns a 20% share in SONGS. Since Edison operates and maintains SONGS, SDG&E is billed by Edison for its share of O&M expense. To avoid relitigating SONGS O&M expense we will use the authorized level adopted in this decision, adjusted for inflation, for SDG&E's 1989 test year general rate case and subsequent attrition increases.

C. Transmission Expense

Edison's original estimate for transmission expense was $77.7 million. Reductions by Edison have lowered this amount to $75.3 million.

Both Edison and PSD recommend that $75.3 million be adopted for test year transmission expense. We will adopt their recommendation.

D. Distribution Expense

Edison's estimate of distribution expense exceeds PSD's estimate by approximately $9 million. The following table details PSD's and Edison's differences.

Distribution Expense Issues

Issue	Edison	PSD	Adopted
	(Dollars in Thousands)		
Trending	$61,807	$57,545	$58,306
Underground Inspection Program	3,894	888	3,894
Storm Damage	16,971	15,280	16,971

1. Trending

Excluding accounts 589, rents and 598, maintenance of miscellaneous distribution plant, Edison used 1985 recorded expenses as adjusted, to estimate test year 1988 expenses for distribution accounts. This method was utilized because of the fluctuations in recorded expenses that resulted from the curtailment of expenses in 1981 and 1982, and the completion of unbudgeted expenditures in 1984. Test year estimates for account 589, rents, were based on existing contractual agreements. For account 598, maintenance of miscellaneous distribution plant, a five-year average of the recorded expenses (1981-1985) was used to estimate the test year 1988 expenses. Edison states this is consistent with the methodology adopted in its last three general rate cases. No adjustments were made in distribution expenses for growth as Edison maintains that additional system growth will be offset by increased productivity.

PSD made adjustments for productivity and operation efficiencies in six of the distribution accounts based on trends using expenses per customer, per substation, and per mile of line of individual labor and non-labor elements within these accounts. The adjustments PSD made were designed to reflect the estimated improvements in the efficiency of operations that were recommended in 55 operational audit reports and in the productivity programs listed by Edison. As a result of PSD's trending methodologies it recommends that Edison's request be reduced by $4.3 million.

2. Account 582, Station Expenses;
   Account 583, Overhead Line Expenses;
   Account 586, Meter Expenses;
   <u>Account 594, Maintenance Of Underground Lines</u>

As stated above, Edison used 1985 recorded expenses to estimate the test year 1988 expenses for these four accounts. There were no adjustments made for growth as Edison maintains any new productivity will serve to offset the continued growth of these expenses.

PSD also used recorded 1985 expenses to estimate test year 1988 for the non-labor expense in these accounts. However, for the labor expense, PSD based its estimates on the downward trends of the recorded years' labor expenses per customer, per substation, per overhead line mile, and per underground line mile. As a result of its analysis PSD adjusted Edison's estimates downward by $3.5 million to reflect gains in productivity and operation efficiencies.

While Edison assumed that increased productivity would offset growth, PSD went beyond Edison's assumption and calculated productivity gains and increased operating efficiency based on the recorded data for these accounts. We find PSD's analysis more accurately reflects the past experience for these accounts and should be adopted.

3. <u>Account 593, Maintenance of Overhead Lines</u>

PSD's downward adjustment of $541,000 was based on a slightly downward trend of the recorded years (1979-1985) direct labor in function account 5252, trimming and removing trees. Edison states that the reason for the downward trend of direct labor is that the number of Edison tree trimming crews (direct labor) has been reduced and replaced with contract crews (non-labor expense). In addition, Edison argues that its test year estimate assumes no change, in constant 1985 dollars, in the level of expenses for account 593.

Since PSD's adjustment does not take into consideration the transition to contract labor and Edison's estimate does, we will adopt Edison's test year 1988 estimate for account 593.

4. Account 597, Maintenance of Meters

PSD made a downward adjustment of $220,000 based on a trend of the total account's non-labor repair costs per customer.

Edison argues that the non-labor trend was downward because the recorded expenses for 1979-1981 were high compared to 1982-1985.

Edison states that the recorded non-labor expenses were lower and relatively more level during the years 1982-1985 because all purchases of meter locking rings (non-labor expense) were assigned to the energy theft program. This changed the account to which meter locking rings were being charged from account 597 to account 587, customer installation expenses. Because PSD, unlike Edison, did not consider the accounting change for meter locking rings, we will adopt Edison's estimate.

5. Workpapers

From the sparring that took place between Edison and PSD over the data for tree trimming and meter locking rings, it appears that Edison's workpapers did not provide a thorough explanation of the estimates for accounts 593 and 597. Edison is reminded that a thorough justification is required for program changes and estimating methodologies proposed in NOI and application filings. If Edison does not follow this procedure in the future, it stands the risk of delaying its rate case.

6. Inspection of Underground Facilities

In its application Edison has included funds for an accelerated inspection program for its underground distribution network. Edison's position is that an extensive program of equipment inspection is necessary to insure the utmost reliability and safety of its distribution system and reduce equipment failure rates. On April 1, 1987, Edison implemented an expansion and acceleration of its inspection of underground facilities. This new three-year program, an accelerated version of the former five-year program, utilizes a sophisticated computer-based system which allows for more effective management of the program and the monitoring of results. It also includes more comprehensive inspection procedures than were previously required. In addition, this program requires a laboratory analysis of the insulating oil in all transformers and switches to determine the existence of properties such as moisture, neutrality, and interfacial tension. The new program was initiated because of the increase in underground switch failures (27.5 per year during the period 1979-1982 to 85.8 per year during the period 1983-1986).

PSD removed all of the incremental increase in labor required to perform this program in the three-year time frame on the basis that the labor would be performed by existing employees and was included in the Company's recorded history for this account. PSD's witness concluded that the inclusion of an additional increment of labor expense double counted the labor requirement for this account.

PSD has also recommended that the laboratory analysis of insulating oil be completed in conjunction with the five-year program, stating that the increases in equipment failures did not appear to be an immediate threat to Edison's underground distribution system.

In response to PSD's position Edison argues that the incremental increase in labor expense represents employees who formerly worked on new business plant construction, and that the employees would be replaced with contract crews. The labor dollars included in the plant budget for those employees will now be utilized to fund additional contract crews. Consequently, there is no double counting of this required labor expense in the estimated years.

Due to the over 200% increase in switch failures, we find Edison's arguments for the need to improve the reliability of its underground distribution system convincing. However, we expect Edison to provide in its next general rate case filing data on the percent of switch failures per year and the age of failed switches. In addition, PSD's claim of double counting employee labor does not take into consideration Edison's use of contract labor for capital projects. We will adopt Edison's requested funding level for its three-year underground inspection program.

7. Storm Damage

Edison utilized a five-year average as its estimating methodology for account 598, storm damages. In support of its estimating methodology Edison states that it was adopted in Edison's 1981, 1983, and 1985 general rate cases.

PSD used an eight-year average, 1979-1986, to consider more years of a climatic cycle. PSD's methodology resulted in a downward adjustment of $1.7 million.

PSD did not provide convincing evidence that consideration of additional years of a climatic cycle would result in a more accurate forecast over time. Consistent with Edison's prior general rate cases and other averages adopted in this decision, we will adopt a five-year average of storm damages.

E. Customer Accounts Expense

There are three areas of customer accounts expense in which Edison and PSD are not in agreement; notice of termination of residential service, uncollectibles, and postage increases.

PSD has estimated that Edison could save $850,000 in accounts 901 and 903 due to Assembly Bill (AB) 2721 (1986 Stats., Ch. 479). AB 2721 amended PU Section 779.1 to remove the requirement of physically posting a notice on the premises of a delinquent customer at least 48 hours before service is terminated. PU Section 779.1 states:

> "(b) Every corporation shall make a reasonable attempt to contact an adult person residing at the premises of the customer by telephone or personal contact at least 24 hours prior to any termination of service, except that, whenever telephone or personal contact cannot be accomplished, the corporation shall give, either by mail or in person, a notice of termination of service at least 48 hours prior to termination."

PSD has interpreted PU Section 779.1 to permit notification of service termination by means other than posting notice of termination on the customer's premises, including by mail or phone. Edison argues that PU Section 779.1 permits notification by mail only when telephone or personal contact cannot be accomplished.

At issue is whether contacting a customer by telephone or in person is less costly than posting a notice on the customer's premises. Edison does not anticipate any savings as a result of AB 2721. In support of this position Edison states a pilot program revealed no savings by telephoning service termination notifications. In addition, Edison interprets personal contact to mean notification by posting.

Since AB 2721 permits telephoning termination notices in lieu of posting, we believe PSD's position, i.e., telephoning should be less costly than posting, has merit. While Edison disputes this, it has only made vague references to a study that does not support PSD's position. Edison has not provided us with convincing evidence that its request of $4.3 million for posting notices is justified in light of AB 2721. We will modify the ALJs' draft decision by reducing Edison's request by $450,000.

The second adjustment which PSD made involves the calculation of the uncollectible rate. PSD used a two-step approach. First, the uncollectible rate was calculated using the last three years' recorded data, adjusted for inter-utility information exchange program (Enercom) savings in 1986. PSD claims that the three-year average is appropriate, because it reflects Edison's significantly improved collection practices, including Edison's new credit scoring system and its recent success at maximizing collections from customers in bankruptcy proceedings. Next, PSD adjusted the calculated uncollectible rate by factoring in the estimated savings from Edison's participation in the Enercom system. PSD estimated that this system, which produced savings of $225,000 in 1986, would achieve $775,000 in savings in 1988 if expanded to other utilities. For this reason, PSD recommends that the Commission give the strongest encouragement to other large investor-owned and municipal utilities to participate in the Enercom program.

With the adjustment for Enercom PSD estimated that Edison's uncollectible rate for the test year would be .203%, a figure that PSD believes compares favorably to the recorded 1986 value of .204%. The revenue requirement impact of this adjustment is $295,000, based on PSD's estimate of 1988 base rate revenues.

Edison agrees with PSD's use of a three-year average of uncollectibles adjusted for recorded Enercom savings, but does not agree with PSD's projected increase in Enercom savings. Edison believes there is no basis for PSD's assumption that Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCal), and/or Los Angeles Department of Water and Power (LADWP) will join Enercom. In support of this assertion Edison states that PSD's witness indicated that LADWP management was opposed to an Enercom concept, PG&E was not contacted, and SoCal had not reached agreement with Enercom. Finally, Edison argues that only 10% of the savings realized in 1986 was derived by locating former Edison customers outside of its own service territory.

Enercom is an independent company that maintains information on accounts determined to be uncollectible and matches this data to turn-on applications on a weekly basis. Enercom retains the turn-on information in their data base for a period of six months and retains the information on uncollectible accounts for a period of three years. The cost of Edison's participation in Enercom is a flat monthly fee of $3,050.

We consider Enercom to be an important tool in minimizing the amount of uncollectibles utilities experience. In Edison's case Enercom is cost-effective by a factor in excess of six to one. With increased participation by utilities, both investor-owned and municipal, the cost-effectiveness of Enercom would increase. We expect the utilities we regulate to seriously consider participating in Enercom and they should anticipate that their progress will be reviewed in future general rate cases.

Because of the uncertainty that other major utilities will participate in Enercom during the test year, we will only reflect Edison's recorded Enercom savings for 1986 in our adopted uncollectible rate. We will adopt an uncollectible rate of .214% based on PSD's three-year average of uncollectibles and Enercom savings of $225,000. Since this is a change from Edison's last adopted uncollectible rate, Edison's annual energy, ECAC, and MAAC rates should reflect the uncollectible rate of .214% effective January 1, 1988.

The final area of disagreement between PSD and Edison concerns postage increases. Edison proposes that postage increases occurring during the test year be noticed by advice filing during the test year and credited to the electric revenue adjustment mechanism (ERAM) balancing account. PSD recommends that postage increases occurring during the test year should only be reflected in Edison's attrition filings.

Consistent with prior general rate case decisions in which prospective increases due to governmental actions were at issue, we will not consider increases during the test year for items which are minor in nature. However, we will allow Edison to reflect postage increases in its attrition filings.

F. Administrative and General (A&G) Expense

Edison's estimate of A&G expense exceeds PSD's estimate by $31.2 million, excluding franchise taxes, RD&D, and load metering expense. PSD developed its adjustment by making specific recommendations after analyzing Edison's requested budget and by placing a ceiling on the amount of increase Edison should be authorized. The following table details the dollar amounts at issue:

Administrative and General Expense Issues

Issue	Edison	PSD	Adopted
	(Dollars in Thousands)		
School Representative Activities	$ 391	$ 54	$ N/A
Customer Service Activities	1,062	924	N/A
Load Metering and Customer Survey	725	0	*
Executive Incentive Compensation	1,635	818	N/A
Outside Services	4,056	4,056	N/A
General Advertising	1,105	0	N/A
Corporate Communications-Annual Report	456	100	N/A
Director's Pension Plan	751	0	N/A
Annual Report Mailing	80	50	N/A
Directors and Officers Insurance	4,864	2,432	4,378
Group Life Insurance	938	801	801
Other Insurance	12,182	9,938	10,964
Medical	66,688	61,788	62,418
Miscellaneous Benefits	(28,434)	(29,497)	N/A
RD&D	24,721	21,799	24,416
A&G Transferred	(26,705)	(26,313)	N/A
A&G Ceiling Adjustment	0	(13,627)	(3,467)

* $725,000 included in customer service and information expenses

Edison utilized a modified budget-based methodology to estimate its level of A&G expense, which it claims is consistent with the Commission's directives in Edison's 1983 test year general rate case decision. The modified budgetary estimating methodology uses 1985 recorded expenses as an estimating base from which increases and decreases in activities are identified for the years 1986-1988.

PSD's recommendations adjust Edison's requested A&G expense in two ways. First, specific adjustments totaling $17.6 million are made. Second, PSD recommends a 10% ceiling based on customer growth be applied to Edison's total increase in A&G expense from 1985-1988. This results in an additional reduction of $13.6 million.

A&G expense is an extremely difficult area in which to control costs. Numerous items from paper clips to the president's salary to medical and insurance premiums are recorded in A&G accounts. Because of this variety in expense categories and their sometimes volatile increases, A&G has not lent itself to any one estimating methodology. In past decisions we have adopted A&G expense estimates using trends, budgets, recorded expenses, and growth in employees, customers, and sales.

Again, we find ourselves in the dilemma of determining a reasonable level of A&G expense. This task is particularly difficult due to the inability to control certain items, such as pension, medical and insurance costs, which together comprise nearly 50% of all A&G expense. Since A&G expense can be divided into costs over which Edison has control and those over which it does not, we will develop our estimate on this basis.

1. Controllable Costs

First, we will address those items over which Edison has control. For this decision we will exclude insurance (accounts 924 & 925 and group life insurance), pension, dental, vision, and medical plan costs, F/MBE program costs, franchise taxes, and RD&D from the items over which Edison has control. The remaining items mainly consist of salaries and office supplies for which Edison is requesting a 11% increase in constant dollars over recorded 1985. For this same period Edison's customer growth is about 8%. Edison's showing for these items is vague with only general references to various program changes and hardly provides adequate justification for its request.

Edison carries the burden of proving that its request is reasonable. This is especially true for A&G accounts which are a catch all for expenses which have no specific identification. As stated above, Edison has not provided adequate justification for its requested increase. Due to this deficiency in Edison's presentation we will limit the increase for the A&G items which are within Edison's control to 8%, the expected customer growth from 1985 to 1988. Since these items are impacted by customer growth, we believe this is a reasonable adjustment. This results in a $5.0 million reduction in Edison's request.

Our adopted expense modifies PSD's second recommendation to apply only to the A&G items over which Edison has control and limits the increase to the percentage change in customer growth for the 1985-1988 period. With the exception of expenses for the abandonment of Ivanpah which are amortized in Account 930, this approach does not endorse any specific programs or activities proposed by Edison, the adjustments made by PSD, or Edison's 1985 expense level. While the adjustment as reflected in Appendix C is shown by account, the adjustment was actually computed based on total controllable A&G expense. It will be left to Edison to manage A&G expense within our adopted level.

In its next general rate application we expect Edison, regardless of its estimating methodology, to provide a detailed justification for each A&G account. This should include a description of each A&G program or activity together with five years of recorded data and an explanation of all significant changes in the recorded and projected data. Finally, we have modified the ALJs' draft decision to reflect the fact that the stock savings plus plan expense is a function of labor escalation.

Excluding RD&D, which is discussed in the section on RD&D, the remaining A&G expense issues are addressed below.

2. Uncontrollable Costs

a. Insurance

PSD recommends that Edison's requested funding of insurance premiums for property, general liability, directors and officers, and group life be reduced by $4.8 million. PSD's adjustment assumes that insurance premiums generally are in decline after a period of precipitous increases. This assumption was based on a review of literature related to the insurance industry and discussions with insurance professionals, including several brokers and a risk manager of a large U.S. corporation. Additionally, PSD observed that Edison's insurance premiums, having increased recently preceded by a decrease in the 1983-1984 period, generally follow market trends. PSD asserts that the combination of the softening of the insurance market and Edison's power in that market as a significant consumer present opportunities for cost savings.

Besides the general changes in the insurance industry, PSD believes that the Fair Responsibility Act of 1986 (Civil Code Sections 1431.1-1431.5) and enactment of the Risk Retention Amendments of 1986 (P.L. 99-563, 100 Stats. 3170) should exert a downward pressure on general liability premiums. Accordingly, PSD reduced Edison's estimates for certain insurance premiums by 20% and 15%. Finally, PSD recommends a $137,000 reduction in Edison's estimated group life insurance premium due to the lack of billed invoices and a split of directors and officers insurance premiums between shareholders and ratepayers.

PSD's proposal that directors and officers insurance premiums should be split between shareholders and ratepayers is premised on a sharing of the benefits. Insurance covering directors and officers of a corporation is designed to protect against shareholder derivative law suits. In the event of a successful shareholder derivative law suit, the insurance policy provides funds to make the shareholders whole for damages caused by wrongful or negligent acts of corporate directors or officers.

Ratepayers also derive benefit from this type of insurance. In the absence of such insurance, there could be a legitimate claim against an officer or director resulting in a substantial damage award that could increase the cost of capital.

Edison believes that PSD's perception of a softening of the insurance market is based on a limited analysis and that property and general liability insurance pose unique risks. In support of its position Edison presents the following arguments:

1. Growth in the size of Edison's assets, and the increased replacement value of those assets due to inflation, will prevent property insurance premiums from declining.

2. Edison's boiler and machinery coverage is a specialized part of property insurance coverage and does not follow the general insurance market.

3. Edison's earthquake coverage has been difficult to obtain at any price.

4. Involvement in a number of alternative insurance companies insulates Edison from the ups and downs of the commercial insurance market.

5. Dramatic increases in litigation and changes in the way that insurance policies are interpreted by courts have caused insurers to pay for losses that they never intended to cover.

With respect to directors and officers insurance, Edison believes it is a normal cost of doing business, which not only covers the directors and officers but also the corporation. Edison argues that directors and officers coverage provides for defense costs without regard to the merits of the law suit and is necessary to attract and maintain well-qualified and able directors and officers.

Due to the increase of derivative law suits in recent years, directors and officers insurance has become commonplace in the corporate world. Without this protection the risks of serving as a director or officer would outweigh the rewards. A well managed and efficient utility is predicated upon having qualified and capable directors and officers and this type of insurance is critical in obtaining and maintaining these individuals. For this reason PSD's recommendation would impose an unwarranted penalty on Edison's shareholders and will not be adopted.

In estimating Edison's insurance premiums we have placed a heavy emphasis on PSD's arguments that there is a softening of the insurance market and that Edison's insurance premiums have generally followed market trends. We also consider Edison's claims concerning the difficulty in obtaining earthquake insurance and its involvement in alternative insurance companies to insulate it from market surges persuasive. After weighting these factors we have concluded that PSD's proposed reductions of 20% and 15% are too drastic. Instead, we will assume that comprehensive liability, directors and officers, and property insurance premiums will be 10% lower than Edison's projections. Since Edison has not provided PSD with the necessary invoices to justify its estimated cost of group life insurance we will adopt PSD's estimate. These combined adjustments result in a $1.8 million reduction to Edison's estimated 1988 premiums. Edison and PSD have agreed to the estimated premiums for crime, nuclear property, nuclear replacement generation, and nuclear liability insurance. These estimates appear reasonable and will not be adjusted.

b. <u>Medical Costs</u>

The method used by Edison to estimate outside provider medical costs took into consideration three factors: (1) overall medical cost escalation factors as provided by the actuary, (2) growth in employee participation, and (3) the ratio of dependents to employees. Edison derived its estimate from 1985 recorded data using the three factors above.

PSD recommends a $4.9 million reduction in Edison's estimated outside provider medical costs. PSD's adjustment is the result of using 1986 recorded data, a lower ratio of dependents to total participants, and no growth in the number of participants.

We will adopt PSD's use of 1986 recorded data adjusted for the increase in employees from the 1986-1988 period. This approach assumes that the existing relationship of total employees to employees participating in the plan remains constant through the test year. We believe this is a reasonable assumption in the absence of data in record to support Edison's or PSD's position. Our adopted estimate of outside provider medical costs is $4.3 million lower than Edison's request.

c. Load Metering and Customer Survey Expense

Consistent with our discussion in the customer service and information section we will move Edison's load metering and customer survey expense to account 908.

d. Franchise Taxes

Edison and PSD are in agreement on the use of a franchise tax rate of 0.73%. Since this is a change from Edison's last adopted franchise tax rate, Edison's annual energy, ECAC, and MAAC rates should reflect the franchise tax rate of 0.73% effective January 1, 1988.

G. Taxes

With the exception of the Superfund Tax, Edison, PSD, and FEA are in agreement on the methodology to be use for calculating payroll, ad valorem, and income taxes. Differences in tax estimates are due to differences in payroll, plant, and expense estimates.

The amount of the Superfund Tax is not at issue, only Edison's classification which treats it as a deductible tax in the computation of income taxes. Edison states that its interpretation of the Superfund Tax is supported by the opinions of tax experts within the utility industry. PSD's classification treats the new Superfund Tax as a nondeductible addition to to Federal income taxes. We will adopt Edison's position which results in a lower estimate of State and Federal income taxes.

While no longer in dispute, FEA raised the issue of the appropriate ad valorem tax rate to be used in determining Arizona property taxes for Palo Verde. Edison and FEA agreed to use the rate of 2.95%.

Besides the Superfund Tax treatment, I.86-11-019 is considering the effect of the Federal Tax Reform Act of 1986 on regulated utilities. Edison and PSD have endeavored to incorporate the provisions of the Tax Reform Act of 1986 in their showings. We will reflect those provisions in this decision. If additional tax changes are required, Edison, should follow the direction set out in our decision in I.86-11-019.

H. Plant-in-Service

For this proceeding PSD devised an approach for estimating plant-in-service that compares prior utility estimates with actual recorded weighted average plant-in-service. Using this methodology PSD found that over a seven-year period, for which data was available, Edison had overestimated its weighted average plant-in-service by an average of 2.28%. PSD's application of this factor to Edison's test year estimates resulted in a difference of $223.9 million in test year plant.

Edison argues that PSD agreed with Edison's beginning of year 1987 plant-in-service estimate and did not recommend adjusting Edison's capital projects for 1987 and 1988. Not only does Edison believe that it is inconsistent to adjust its weighted average plant without adjusting plant-in-service or plant additions, it also points out that PSD's methodology could result in plant estimates that are lower than recorded.

In contrast, Edison developed its 1988 plant-in-service estimate by adding forecasted plant additions to 1985 recorded plant-in-service. Estimated plant additions for the years 1986-1983 were obtained from Edison's five-year plant and work element budget and forecast. Edison's plant additions are categorized by class of plant and by month and year of operation. From this data month-by-month plant balances by class of plant, including construction overheads and plant retirements, were calculated for the forecast period.

The testimony of PSD's witness reflects little preparation and a lack of understanding of how plant estimates are developed for ratemaking. First, PSD's witness was unable to provide basic information concerning estimated plant additions for 1987 and 1988. Next, PSD's witness developed an adjustment factor from an analysis of recorded versus budgeted plant. Finally, this adjustment factor was applied to Edison's estimated total plant which reduced Edison's net plant additions by 44% and resulted in no recovery for .7% of recorded plant.

We find PSD's approach of adjusting total plant based on a factor developed from using budgeted versus recorded plant inappropriate. Even if PSD's adjustment was corrected for this flaw, we find its methodology a poor substitute for a detailed analysis of Edison's estimated construction projects taking into consideration their need, estimated cost, and expected operation date. We consider Edison's detailed estimating methodology reasonable and will adopt its plant-in-service estimates for test year 1988.

I. Depreciation

During the September update hearings Edison revised its average service lives and net salvage amounts for transmission and distribution classes of plant. This change resulted in lower depreciation rates and decreased Edison's depreciation expense by $69.3 million. PSD has agreed to Edison's revised depreciation rates. The only difference between Edison's and PSD's estimates of depreciation expense and reserve is due to differing plant estimates. We will adopt Edison's revised depeciation rates for use in this decision.

J. Plant Held for Future Use (PHFU)

PHFU includes land and plant related items that have been acquired by Edison for use in the future. In its application Edison requested that it be allowed to earn a return on $128.2 million in PHFU for test year 1988. Since its application was filed, Edison reevaluated its PHFU estimate in light of the PHFU guidelines it and PSD developed and agreed to reduce the amount by $7.1 million.

During the course of its audit, PSD questioned Edison's specific plans for using 56 parcels of land in PHFU. PSD claims that under current plans, the average time that these parcels would remain in the PHFU account is 27 years and as of January 1, 1987 they have averaged over 16 years in PHFU. Additionally, PSD points out that the carrying charges for the ratepayers (18.07%, return times net to gross) is substantially greater than for Edison (10.75%, return on rate base). Faced with this circumstance, PSD recommends that all of the 56 parcels be excluded from rate base for the test period, an adjustment of $20.4 million. Finally, PSD identified a parcel valued at $520,000 that was double counted in Edison's application.

In response to a request by ALJ Ferraro, PSD propounded a series of guidelines to govern the length of time that items could be retained in PHFU. The guidelines, attached as Appendix B, provide for the following:

1. Distribution substations and transmission plant (not related to new power plants) could be held in PHFU and not placed in Edison's plant expenditure review committee (PERC) budget for five years. If by the end of five years, the property has not

been included in the PERC budget, it would be removed from PHFU until it is included in a future PERC budget.

2. Generation and transmission plant (related to new power plants) can be held in PHFU and not be included in the PERC budget for ten years. If at the end of ten years, the property has not been included in the PERC budget, it would be removed until it is included in a future PERC budget.

While PSD states that the guidelines may be valuable for the future, implementing them on a prospective basis will not remedy the injustice that ratepayers have endured by absorbing significant carrying costs over past years.

Edison worked with PSD in developing the guidelines and believes that they should be adopted prospectively. Edison states that the guidelines give guidance, are fair and workable, and benefit Edison and its ratepayers. Finally, Edison points out that the guidelines give Edison appropriate flexibility, provide reasonable compensation, and give ratepayers protection from paying for property that may ultimately end up not being needed.

Adoption of the guidelines prospectively results in a $7.1 million reduction from the amount Edison originally requested be included in PHFU. Edison is in agreement with this reduction, but is opposed to PSD's recommended exclusion of $20.4 million from PHFU. Edison argues that PSD's recommendation is unfair because the needs for the property were not considered and it was based solely on PSD's judgement that the property has been in PHFU too long.

PHFU is an area in which we do not have specific criteria for judging the reasonableness of a utility's property acquisition policies. Because of this, utilities do not have a strong incentive to closely monitor their procedures for acquiring and maintaining PHFU. ALJ Ferraro directed PSD and Edison to work together to develop guidelines which could be used to judge the reasonableness of utility expenditures on PHFU. As a result, PSD and Edison developed guidelines and agreed to their use in the future. We find these guidelines reasonable and will adopt them for use in this and Edison's future general rate cases. In addition, we will direct our Evaluation and Compliance Division to notify the energy utilities under our jurisdiction that we expect to adopt similar guidelines in their next general rate case.

Although PSD and Edison are in agreement that the guidelines should be used in future general rate cases, they are in disagreement over their use in this proceeding. PSD's auditors are concerned over the length of time that ratepayers have paid high carrying charges on 56 parcels in PHFU, while Edison has identified a specific use for most of these properties and argues that it would be unfair to apply the guidelines retroactively.

Because Edison has identified a specific use for most of the properties at issue, we will not adopt PSD's recommendation in its entirety. However, starting January 1, 1989 we will apply the adopted guidelines as if they were effective prior to the acquisition date of all items in PHFU. This will result in a reduction of $16.2 million from Edison's original request for 1989. For test year 1988 we will reduce Edison's original request by $7.5 million. This represents $7.1 million, Edison's agreed reduction, and $520,000, PSD's double counting adjustment.

By delaying full implementation of the guidelines Edison should have ample opportunity to manage its PHFU account to the level adopted in this decision. Edison can accomplish this by delaying future purchases, selling property not needed in the near future, placing property in plant-in-service as it becomes used and useful, or by transferring property to nonutility property. We believe, by providing ratepayers with lower carrying charges now and in the future and shareholders with the opportunity to adjust to this change, the interests of ratepayers and shareholders are fairly balanced.

K. Working Cash Allowance

With one exception Edison and PSD are in agreement on the methodology for calculating the allowance for working cash. The only remaining issue concerns the weight that should be given to the lag in the State income tax deduction used in determining Federal income taxes. In its estimate of working cash allowance Edison reflects the fact that the previous year's rather than the current year's State income taxes are used as a deduction for calculating corporate Federal income taxes. Consistent with prior Commission decisions, PSD recommends that no consideration be given to this issue in estimating working cash allowance.

This issue was first raised in PG&E's general rate case A.85-12-050. By D.86-12-095 in that proceeding we ordered workshops to be conducted which would include other energy utilities. Edison has participated in those workshops, but at this time there has not been a final resolution of the matter. Accordingly, we will adopt PSD's recommendation, but allow Edison's general rate case to remain open until this issue is finally resolved. Edison will be allowed to record in a memorandum account the difference between the adopted revenues and those Edison's proposed working cash methodology would yield. The difference in revenues recorded in the memorandum account should accrue interest at the energy cost adjustment clause (ECAC) balancing account rate.

L. Attrition

Edison and PSD are in agreement on the method of calculating attrition. Additionally, both recommend that the 1989 ERAM base level should be increased by $9.8 million to reflect a change in jurisdictional allocation due to a decrease in FERC jurisdictional sales. Edison and PSD recommend no change in the jurisdictional allocation factors for 1990. Finally, the revenue requirement associated with Edison's optional time of use meter plan will be reflected in calculating attrition for 1989 and 1990. This item is discussed in more detail in the section on rate design. Attached as Appendix D is the format we expect Edison to use in developing its attrition filings.

V. Major Issues

A. Cost of Capital

In recent general rate cases for the large electric utilities, we have indicated that a utility should be authorized a return on common equity (ROE) that is commensurate with market returns on investments having corresponding risks. We also have repeatedly stated that there are three considerations which we rely upon to implement this objective:

1. Cost of capital varies in the same direction as changes in the general level of inflation and interest rates.

2. Market cost of equity capital reflects risks, such as the exposure of a utility's earnings to variability in fuel costs, sales levels, as well as uncertainties regarding the cost of prior capital investments.

3. The application and interpretation of financial models may not accurately reflect all of the intricacies of the financial market.

In evaluating the proposals before us from Edison, PSD, and FEA we will place heavy emphasis on these principles. Each party's position on the various cost of capital issues is summarized in the table below followed by a detailed discussion of the issues.

Cost of Capital Recommendations for Test Year 1988

PSD

Component	Capitalization Ratio	Cost Factor	Weighted Cost
Long-term Debt	47%	9.26%	4.35%
Preferred Stock	7	7.80	.55
Common Equity	46	12.00*	5.52
Total	100%		10.42%

* Midpoint of Range.

Edison

Component	Capitalization Ratio	Cost Factor	Weighted Cost
Long-term Debt	47%	9.26%	4.35%
Preferred Stock	7	7.88	.55
Common Equity	46	13.75	6.33
Total	100%		11.23%

FEA

Component	Capitalization Ratio	Cost Factor	Weighted Cost
Long-term Debt	47%	9.17%	4.31%
Preferred Stock	6	7.80	.47
Common Equity	47	12.55	5.90
Total	100%		10.68%

Before moving to the cost of capital issues in this proceeding, it should be noted that this decision will only address Edison's cost of capital for test year 1988. To more accurately reflect changes between rate cases, we expect utilities, as discussed in D.85-12-076, to address return on equity in their annual attrition filings. In addition, we wish to make it clear that the utilities are also expected to reflect in these filings any changes which would affect their last adopted capital structure. Finally, Edison's MAAC and IMAAC should be adjusted as of January 1, 1988 to reflect the adopted ROE in this decision.

1. Capital Structure

Edison and PSD made specific recommendations on capital structure, while FEA reviewed the estimates and adopted PSD's original capital structure. The specific recommendations are shown in the table below.

Comparison of Edison and PSD Capital Structures

	Edison	PSD*		
	1988-1990	1988	1989	1990
Long-Term Debt	47%	47%	46%	45%
Preferred Stock	7%	6%	6%	5%
Common Equity	46%	47%	48%	50%

* Table Reflects PSD's Original Position. PSD Adopted Edison's Revised Capital Structure After the September Update Hearings.

Edison's recommendation is based on a target capital structure which was designed to help maintain its financial integrity while minimizing costs to ratepayers. Although Edison originally forecasted that its common equity ratio would increase to 48% or more during the 1988-1990 period, in the September update hearings it lowered its forecast to 46%. Edison's change in common equity percent reduced its base rate revenue increase by $18 million and its total revenues including MAAC by approximately $25 million. According to Edison's chief financial officer the reasons for this revision are: (1) to mitigate uneconomic bypass and (2) facilitate the move to marginal cost-based rates.

PSD originally proposed a separate capital structure for each year of the test period based on Edison's financing plan. In support of that recommendation PSD argued that: (1) it accurately reflects Edison's financing year by year rather than Edison's front loading the expensive components of capital costs and (2) if the capital structure requires adjustment, it can be made in the context of the attrition rate adjustment mechanism. After the September update hearings, PSD submitted Exhibit 245 in which it adopted Edison's revised capital structure.

In light of Edison's updated testimony we have an opportunity to provide ratepayers with lower rates without jeopardizing Edison's financial standing. We will adopt Edison's revised capital structure for test year 1988.

2. Long-Term Debt

Edison, PSD, and FEA made recommendations regarding the cost of new debt and the resulting embedded cost of debt for the 1988-1990 period. Their estimates of the incremental cost of long-term debt are set forth in the following table.

Incremental Cost of Long-Term Debt

	1987	1988	1989	1990
Edison	10.00%	10.00%	10.00%	10.00%
PSD	9.49%	10.37%	9.82%	9.60%
FEA	9.63%	10.94%	12.06%	11.06%

PSD relied on the DRI September 1987 forecast of interest rates for AA utility bonds, FEA adopted the Wharton Econometrics forecast, and Edison reviewed current forecasts and used judgement to develop its recommendation.

FEA finds fault with Edison's judgement because Edison lowered its requested return on common equity from its original application to reflect lower interest rates, but retained its estimated cost of new debt. PSD argues that neither PSD or Edison has the resources to develop and maintain forecasting models for interest rates; both must rely upon forecasting services with access to vast amounts of data and an acknowledged expertise in the field.

While there are many areas in developing estimates for the test year to which judgement must be applied, we find Edison's approach unnecessary in light of the availability of acknowledged expert forecasting services. Since DRI forecasts are used to develop the non-labor escalation factors in this decision and in the attrition rate adjustment mechanism, we will use DRI's estimated cost of long-term debt. However, we note that our decision today in the consolidated attrition proceeding adopts DRI's November forecast of AA utility bonds. To be consistent with the attrition proceeding we will use DRI's November forecast of 9.68% for Edison's incremental cost of long-term debt.

3. <u>Tax-Exempt Financing</u>

A portion of Edison's debt is represented by variable-rate tax-exempt pollution control bonds. Based on their historical relationship with Moody's double-A utility bond yields, Edison estimates an interest rate of 6.4% for its tax-exempt issues in 1988. PSD derived its estimated interest rate of 5.38% by using the historical relationship between tax-exempt issues and the prime rate. PSD slightly increased its forecasted interest rate to recognize the decline in marginal tax rates due to the Tax Reform Act of 1986.

Both of these approaches appear to be flawed. PSD criticizes Edison's forecasting model for yielding a poor correlation between interest rates for tax-exempt bonds and double-A utility bonds. In response, Edison states that the interest rate for its tax-exempt bonds is no longer based on the prime interest rate.

The only reasonable guide we have to judge the results of these recommendations is a comparison with recent recorded data. PSD's prior forecast for 1987 was only 0.1% higher than recorded data for the first quarter of 1987. Since there was only a slight difference between PSD's forecast and recorded data, we will adopt PSD's estimated cost of variable tax-exempt bonds. However, we are not convinced that PSD's methodology will always yield the best results and instruct PSD to address Edison's concerns before recommending its use in future proceedings.

4. Preferred Stock

Edison issues two types of preferred stock: sinking fund and perpetual. Sinking fund securities have a fixed-term and are essentially equivalent to debt instruments, because they are issued for a specific term at a fixed dividend rate. Perpetual securities are similar to common equity in that they do not have a sinking fund provision or a specific term.

The issue which PSD raises is Edison's proposed recovery of issuance costs on perpetual securities which have been called. Edison proposes to recover these costs by increasing the embedded cost of preferred stock. This is consistent with the recovery of unamortized issuance costs when sinking fund preferred stock is called. PSD takes the position that perpetual and common equity stock are similar and should be treated in a like manner. Since issuance costs for common equity stock are not recovered from ratepayers, PSD recommends that issuance costs for perpetual stock not be recovered from ratepayers.

In Edison's reply brief it points out that San Diego Gas & Electric Company (SDG&E) in D.86-12-007 was authorized to recover the unamortized issuance costs associated with perpetual securities. Consistent with D.86-12-007 we will allow Edison to recover the unamortized issuance costs for the perpetual securities it requested.

Edison's request for recovery of issuance costs only increases the cost of preferred stock by 8 basis points. Due to rounding, this small increase actually has no impact in the overall rate of return and does not affect the revenue requirement for test year 1988.

5. <u>Common Equity</u>

Of all the issues in the cost of capital area, ROE, due to the dollars involved, was the most heavily contested. A summary of the various positions of the parties is shown in the following table.

<u>Summary of ROE Recommendations</u>

Party	ROE
Edison	13.75%
PSD	11.75%-12.25%
FEA	12.55%

While all three parties submitted testimony showing the results of various financial models as the starting point for establishing ROE, they cautioned that the model results must be tempered by judgment. Risk premium and discounted cash flow (DCF) models were presented by all parties. Additionally, PSD developed a capital asset pricing model and FEA made an analysis of the earnings of comparable utilities. The following table summarizes the results of these models.

<u>ROE Model Results</u>

Party	Model	ROE
Edison	Risk Premium	13.5%-15.0%
	DCF	12.4%-14.5%
PSD	Risk Premium	13.5%-18.4%
	DCF	11.5%-12.5%
	Capital Asset Pricing	11.7%-12.6%
FEA	Risk Premium	12.3%-14.0%
	DCF	11.5%-13.0
	Comparable Earnings	13.1%

Because these models are only used to establish a range for ROE, we will not repeat the detailed descriptions of each model contained in the parties' exhibits. Additionally, the parties have put forth arguments in support of their analyses and criticizing the input assumptions used by others. As can be seen from the above table these models yield a wide range of results depending upon the choice of various input assumptions. Our review of these arguments indicates that they do not significantly alter the model results shown above. We believe these model results provide a reasonable range from which to choose an appropriate ROE and will be used as a guide in selecting Edison's ROE. In the final analysis it is the application of our judgement that is crucial, not the accuracy of a particular model.

In applying judgement to the results of its models, Edison, as detailed by the testimony of its chief financial officer, John Bryson, identified the major items which justify its proposed ROE. These are: maintaining its financial integrity and the increased risk associated with regulatory changes, competition, system operations, and uncertain economic conditions.

Edison argues that it is in the best interest of both its customers and investors to maintain its financial integrity and thus retain access to the lowest cost funds available during all market conditions. This, Edison claims, requires a ROE of 13.75% in order to keep its double-A credit rating.

As further justification for its proposed ROE, Edison states that in recent decisions, two broad categories of risk allocation have been reflected: (1) retroactive imposition of risks to the utility based on results of prior conduct, and (2) prospective allocation of risk associated with uncertain future events. Edison believes that investors perceive these as new risks and demand a higher return.

Second, Edison identifies competition from third-parties and self-generators as a new risk in the eyes of investors. This risk occurs because these companies are not subject to traditional utility constraints and obligations, but are allowed to compete with utilities for customers and new resources.

Third, Edison argues that it no longer has sole responsibility and control over its sources of energy. This results from Edison's increased reliance on third-party generation and purchases from distant utilities. In addition, a significant amount of Edison's generating resources are nuclear which can be adversely affected by events wholly outside Edison's facilities, service area, or control.

Finally, Edison points to the volatility in the economy, especially the uncertainty in the prospective levels of inflation, interest rates, and oil prices.

PSD counters by stating that the last decade has seen the implementation or refinement of a variety of rate mechanisms and policies, all of which have generally served to diminish the risks attendant to operating an electric utility. These include: ECAC which protects the utility from the variability of fuel costs; ERAM which insulates the utility from the vagaries of electric system sales; the attrition rate adjustment which provides opportunities for base rate adjustments in the years between general rate cases; MAAC which provides rate recognition for major capital projects; and the rate case plan which insures timely processing of utility rate applications.

In addition, PSD argues that Edison's recent financial performance indicates it is a strong company, with a risk profile that is relatively low. To support this claim PSD points to the following Edison financial indicators:

1. 1986 was the sixth consecutive year of record earnings.

2. Allowance for funds used during construction has declined as a percentage of earnings for five consecutive years.

3. In 1986 80% of capital needs were provided through internal generation of funds, the highest level in 25 years.

4. Earnings have averaged over 30 basis points in excess of the authorized return on equity during the last five years.

5. Declared dividends on common shares have outpaced the consumer price index over the last five years.

6. Common shareholders have realized an average annual return of 28.5% over the last five years.

7. Common shares were selling at a 54% premium above book value at the end of 1986.

8. A double-A bond rating has been maintained for more than a decade.

Besides these healthy financial indicators, PSD points out that Edison no longer faces uncertainty with regard to the final disposition of SONGS and, through subsidiaries, has made investments in the area of QF energy production. Finally, PSD believes that today's market reflects a perception by investors that risks are lower than in the past and proposes that Edison receive a rate of return at the lower end of the recommended ranges.

As we stated at the outset, our ROE determination is largely influenced by changes in and the level of inflation and interest rates in combination with the results of various financial models. Other factors, such as the financial condition of the utility and changes in regulatory and business risks, are considered, but typically have a lesser impact on the final ROE.

In Edison's last general rate case, for test year 1985, we authorized a 16% ROE. Since that decision, there has been a considerable reduction in interest and inflation rates. These lower and more stable factors support a significant reduction in the authorized return. Some of this reduction has already been reflected by the negotiated agreement between Edison and PSD which resulted in authorized returns of 14.6% for 1986 and 13.9% for 1987.

All parties, including Edison, recognize that further reductions below the currently authorized ROE of 13.9% are justified. The only question is the magnitude of the reduction. Today's economic indicators paint a much rosier picture than those of three years ago. Interest rates for long-term debt are estimated to be in the range of 10%, inflation is projected around 4%, and Edison has just had the best financial performance in its history. This is a considerable improvement over test year 1985 in which long-term interest rates were expected to be 13%, inflation estimated around 6%, and Edison was facing a major reasonableness review of SONGS 2 and 3.

Edison's showing places a heavy emphasis on maintaining its financial integrity. While we feel this is an important goal for Edison and its ratepayers, it is not the Commission's charge to insure Edison achieves this goal. Our objective is to authorize a ROE commensurate with market returns on investments having corresponding risks. In this way we provide Edison with the opportunity to maintain its financial integrity through effective management.

Finally, Edison claims that it faces substantial risk due to recent regulatory changes, system operation changes, and uncertain economic conditions. We agree with Edison that all of these are factors considered by investors and we will give recognition in our adopted ROE to certain changes in risk. However, three years ago there also was uncertainty in the economy and Edison's nuclear operations and purchases from distant utilities were essentially as they are today. No change from the treatment provided these items in Edison's last general rate case appears warranted at this time.

In summary, we believe that the low and stable levels of interest and inflation rates coupled with the financial models presented by the parties all point toward a significant reduction in Edison's authorized ROE. After taking into consideration all of the evidence relative to market conditions, Edison's financial health and exposure to risk, and the testimony on financial models, we conclude that a ROE of 12.75% is just and reasonable for test year 1988. Our adopted ROE produces an overall rate of return of 10.75% which we feel is sufficient to attract and compensate investors.

As discussed previously our adopted ROE is only for test year 1988. For subsequent years it will be subject to review in Edison's attrition filings. The following table details our adopted cost of capital.

Adopted Cost of Capital

	Contribution Ratio	Cost Factor	Weighted Cost
Long-term Debt	47%	9.22%	4.33%
Preferred Stock	7	7.88	.55
Common Equity	46	12.75	5.87
Total	100%		10.75%

B. Nuclear Fuel and Coal Fuel Inventory Financing

Edison proposes to phase-out its nuclear fuel lease for SONGS and include all nuclear fuel and coal inventory in rate base. PSD recommends that the carrying costs on all nuclear fuel and coal inventory be calculated using the short-term debt rate in ECAC.

1. Nuclear Fuel

In 1974 Edison entered into a lease arrangement to procure its nuclear fuel requirements for SONGS. This lease arrangement permitted Edison to finance its nuclear fuel at favorable short-term rates which, because of the lease structure, was not reflected on the company's balance sheet. Due to an accounting change made by the Financial Accounting Standards Board, Edison, beginning in 1987, must reflect capital leases on its balance sheet. Accordingly, Edison plans to purchase its nuclear fuel and phase-out the nuclear lease over time. In its application Edison has requested rate base treatment for a portion of the nuclear fuel it will own.

PSD sees the issue differently and proposes that SONGS nuclear fuel carrying costs continue to be recovered through ECAC, based on short-term rates. In addition, PSD recommends that Palo Verde nuclear fuel carrying costs be recovered in a like manner through ECAC. PSD believes this is appropriate for the following reasons:

1. The Commission has pursued a policy in recent years of removing fuel inventory assets from rate base and allowing the recovery of carrying costs at short-term rates through ECAC. There is no reason to make an exception for nuclear fuel.

2. The Commission recently issued D.87-05-059, authorizing Edison to guarantee short- and intermediate-term debt instruments issued by one of its subsidiaries for the express purpose of financing nuclear fuel.

3. Edison is not required to terminate its lease and there is no reason why ratepayers should pay higher carrying costs because of a change in how capital leases are treated in Edison's financial statements.

PSD estimates that the increased cost for full recognition in rate base of nuclear fuel, including Palo Verde, would be over $48 million and even with Edison's phased-in approach the increased cost would be over $8.5 million in test year 1988.

Edison argues that nuclear fuel should not be afforded the same treatment as other fuel because of its four to six year life and unique characteristics. Edison states that nuclear fuel has a much longer life than other fuels, cannot be used (burned) for up to two years, goes through extensive processing before it can be loaded into a plant, and is plant specific. Edison believes financing nuclear fuel with permanent capital as reflected in its imbedded-cost of debt appropriately matches asset and liability life and risk.

Since it entered into the nuclear leasing arrangement, Edison states that accounting standards, bond rating agencies, and investor perceptions toward off-balance sheet financings have become more stringent. As a result Edison believes that equity support is needed for nuclear fuel and proposes to achieve this through rate base treatment.

To minimize the impact on rates Edison proposes to phase nuclear fuel financing into rate base over a 10-year period. Because Edison believes that its credit ratings will not be affected if it is perceived as moving toward an appropriate capital structure and ratemaking treatment, it is willing to forego full equity support for the lease to mitigate rate increases. Edison estimates that its proposal for the SONGS nuclear fuel will increase rates by only $2.1 million in 1988 and $12.3 million over the three-year rate cycle.

Although Edison points out that the operating and life cycle characteristics of nuclear fuel are not the same as coal, gas, and oil, we believe that this is not enough to warrant a different ratemaking treatment. In fact, Edison proposes to finance nuclear fuel with a combination of short- and intermediate-term debt. While this might indicate that there is a need to factor in the cost of intermediate-term debt in deriving the carrying cost associated with nuclear fuel, it does not justify rate base treatment.

Edison also believes that the accounting change in and investor perceptions toward off-balance sheet financing require a change in its financing of nuclear fuel. We feel that these factors may affect risk, bond ratings, and the benefits of leases, but, again, they do not necessitate a change in ratemaking treatment.

As stated in prior decisions, we consider short-term debt instruments to be preferable in determining carrying charges on fuel. Fuel is a commodity that can be used as collateral for financing and is distinguishable from fixed plant and land. These factors lead us to the conclusion that fuel should not be afforded rate base treatment, regardless of its characteristics. As a result, we will not adopt Edison's proposed rate base treatment for SONGS unspent nuclear fuel and will direct Edison to calculate carrying costs on Palo Verde unspent nuclear fuel using the cost of short-term debt.

We will authorize Edison to record carrying costs on unspent nuclear fuel based on short-term debt and address these costs in ECAC proceedings. Since the carrying costs for SONGS unspent nuclear fuel is currently included in Edison's ECAC balancing account, no ratemaking change is necessary for this fuel. However, carrying costs for Palo Verde unspent nuclear fuel are included in Edison's intermediate major additions adjustment clause (IMAAC). Consistent with our discussion above, Edison should as of January 1, 1988 stop accruing carrying costs on Palo Verde unspent nuclear fuel in the IMAAC account and start accruing 100% of these costs in the ECAC balancing account based on the ECAC interest rate.

2. Coal Fuel Inventory

Edison has included in rate base $11.5 million for the minimum coal inventories necessary to support its coal-fired generation resources at Mohave and Four Corners. These minimum coal inventories are required in the event of a mine strike or other event which could interrupt the supply of coal. Both Four Corners and Mohave generating stations are remotely located, lack rail connection and waterways, and cannot be economically supplied from other mines should a supply interruption occur.

Consistent with its recommendation for nuclear fuel, PSD proposes that Edison's coal inventory be removed from rate base and carrying costs on coal inventory be based on short-term debt, recoverable through ECAC.

Again we acknowledge that some fuels such as coal have unique characteristics, but this does not justify rate base treatment. Our discussion in the nuclear fuel section above concerning carrying costs is equally applicable for coal inventory. We will not authorize Edison to receive rate base treatment on coal inventory. Starting January 1, 1988, Edison shall be allowed to accrue in its ECAC balancing account carrying costs on its coal inventory based on the ECAC interest rate. Edison's coal inventory level is not in dispute, we find its requested level reasonable for calculating carrying costs until Edison's next reasonableness review.

C. Palo Verde Reasonableness Review

Edison requests recovery of the costs associated with the California, Arizona, New Mexico and Texas (Four State Committee) investigation into the management and construction of Palo Verde. The costs for which Edison is requesting recovery were incurred for the purpose of paying for the investigation conducted by the Four State Committee and preparing an "affirmative case". The affirmative case was intended ultimately to demonstrate the reasonableness of Edison's investment at Palo Verde in the Palo Verde MAAC proceeding. The estimated cost associated with the investigation conducted by the Four State Committee and the preparation of Edison's affirmative case is $3.9 million. Edison is requesting that this amount be recovered in equal amounts over three years beginning in 1988.

FEA recommends that the Commission not allow the Company to recover $2.4 of the amount requested by Edison. According to

FEA, these costs are related to the preparation of Edison's affirmative case and were not intended by the Commission to be recovered.

Edison argues that its affirmative case costs are similar to expenses associated with utility participation in (and preparation for) regulatory proceedings before the Commission and other agencies. The latter costs, Edison states, are normal costs of doing business and currently recovered in rates.

Although Edison's affirmative case costs for Palo Verde are similar to regulatory Commission expenses normally recovered through rates, Edison's request for recovery is not similar. First, Edison has not provided adequate justification that these costs were reasonably incurred. Second, regulatory Commission expenses are recovered prospectively, but Edison is requesting retroactive recovery.

Other than stating that its affirmative case was intended to demonstrate the reasonableness of its Palo Verde investment, Edison has not provided an explanation of what the costs were for and to whom they were paid. Assuming adequate justification, recovery of these costs requires Edison to seek our approval prior to their incurrence. Either by separate application or in an earlier proceeding, Edison should have requested approval for the expected cost of an affirmative case or requested the establishment of a mechanism for tracking these costs for later recovery. For these reasons Edison will not be authorized recovery of $2.4 million in affirmative case costs for Palo Verde.

D. Resource Plan

PSD is the only party that addressed the reasonableness of Edison's resource plan. During its participation PSD made specific recommendations concerning three Edison resource items: 1) the future status for many older and less efficient oil and gas generating units, 2) reduced minimum operating levels for various oil and gas generating plants, and 3) expansion of the Pacific

Northwest (PNW) direct current (DC) intertie (discussed in a separate section).

1. Over View of Resource Planning

In sharp contrast to the situation Edison and other California utilities found themselves in less than a decade ago, Edison now has excess capacity that will last until well into the 1990's. This brings the "stay the course" policy of recent general rate cases into question. Under "stay the course" budget levels for resource related programs, such as research and development, conservation, and load management, were maintained at existing levels.

The approach which Edison now seems to embrace is to reduce high cost supplies and reduce expenditures on conservation and load management programs while maintaining the infrastructure necessary to gear up these programs. This policy would keep Edison's options open consistent with a least-cost strategy.

In support of its flexible policy for resource planning Edison provided a fairly detailed examination of its resource plans and associated forecasts spanning nearly twenty years and concluded that:

> "It is futile to pretend that our predictions of the future will be any more accurate than those of the past. The only certainty about the future is change; and
>
> What does this tell us about our future plans? We should separate the forecasting function from planning in the sense that even if the forecast turns out to be wrong, our planning is right."

In support of its new planning approach, Edison has presented a series of 12 scenarios, endeavoring to show the flexibility in its current (fall 1986) resource plan. Using this resource plan as the base case, there are a total of four resource options identified if lower demand forecasts were to result -- lower by as much as 5000 megawatts (MW). These are:

1. Change the number of units placed on cold standby (a storage option for older, less efficient oil and gas units).

2. Eliminate the Big Creek expansion project (an augmentation of Edison's Big Creek hydroelectric system).

3. Reduce the number of QFs; independent energy producers who's output Edison is required by law to purchase.

4. Cut back on energy management programs (conservation and load management).

In the event higher growth or an array of problems lead to the need for additional resources -- as much as 5000 MW more -- Edison has identified six resource options. They are:

1. Reduce the number of units placed in cold standby.

2. Increase purchases.

3. Develop Edison renewable and alternative resources (only in the scenario involving competitive ratemaking).

4. Install combustion turbines.

5. Increase energy management.

6. Build coal plants.

PSD generally agrees with Edison's policy, but does not consider its resource plan to be very flexible or dramatically different from past plans. To support its position PSD points out that Edison:

1. Has no effective control over the number of QFs.

2. Is currently planning on filing for a certificate of public convenience and necessity (CPCN) for the Big Creek expansion project.

3. Needs 8 to 9 years to build a coal plant; slightly less for Ivanpah which has received partial California Energy Commission (CEC) approval.

4. May not be able to rely on purchases from other utilities for the same reasons that Edison would require additional resources.

Additionally, PSD states that with the exception of the Ivanpah project the biggest single source for Edison to either increase or decrease its resources is by adjusting the number of units in cold standby. PSD is concerned that the economic ramifications associated with the units recommended for cold standby can not be ascertained. These units are older, less efficient units, which in PSD's view could have high operation and maintenance costs and are sensitive to changes in oil and gas prices.

PSD's views, as detailed above, form the basis for its specific recommendations concerning Edison's plant refurbishments and retirements, minimum generation improvements and expansion of the DC intertie. These are discussed below.

2. Plant Refurbishments and Retirements

Over the last several years Edison has analyzed the need to refurbish or retire its oil and gas generating units which have approached or exceeded their original design or economic lives. In this proceeding Edison has no plans to retire or refurbish (preserved retirement) any of these units. Edison does plan to place various units totaling 894 MW into standby reserve by 1989. These units are identified in the following table.

Units Planned for Standby Reserve

Unit		Capacity (MW)	Placement Date
Etiwanda	1	132.0	1987
	2	132.0	1987
Highgrove	1	32.5	1988
	2	32.5	1988
	3	44.5	1988
	4	44.5	1988
Alamitos	1	175.0	1988
	2	175.0	1988
San Bernardino	1	63.0	1988
	2	63.0	1988
Total		894.0	

The cost of placing these units into standby reserve totals $343,000 of which Edison has requested $245,000 for test year 1988. Rather than refurbish any units, Edison is currently proceeding with the concept of sequenced maintenance, repair or replacement of deteriorated parts during routine maintenance outages.

CEC in preparation of its Electricity Report 6 (ER 6) reviewed Edison's plans for these aging units. As a result of the CEC analysis it made certain recommendations in its ER 6. PSD argues that Edison's plans are inconsistent with the CEC recommendations. As summarized by PSD, these recommendations state that Edison should:

1. Retire 1,760 MW by 1997.
2. Place 191 MW into standby reserve for three to five years beginning in 1990.
3. Not proceed with a refurbishment program for most of its oil and gas units.

Of primary concern to PSD is the absence of information from which to evaluate Edison's proposals and the inconsistency in the information that does exist.

PSD's specific concerns are listed below:

1. Edison's proposals are inconsistent with the CEC recommendations in ER 6. Whether the CEC conclusions are appropriate or not, the inconsistency needs to be addressed.

2. There has been no comprehensive update to the fall 1983 study performed by Edison, even though there have been dramatic changes in Edison's resource situation, fuel prices, etc.

3. Edison has repeatedly rejected PSD's requests to provide updated studies or information supporting its proposals for the oil and gas units.

PSD believes that without a comprehensive study evaluating the range of alternatives for the oil and gas units and a value-based reliability criteria, it is inappropriate to make commitments as to the future of these units. As a result, PSD recommends that: (1) a study which conforms with the guidelines shown in Exhibit 53 be provided in conjunction with Edison's fall 1988 resource plan, and (2) a value-based reliability criteria be submitted within three months from effective date of this decision.

Edison agrees with PSD's recommendations, however, it requests that: (1) the value-based reliability criteria be submitted coincident with its fall 1988 resource plan and (2) it be allowed to deviate from PSD's guidelines in Exhibit 53 in order to develop an appropriate study that meets PSD's needs.

We find PSD's recommendations as modified by Edison's requests reasonable.

3. <u>Minimum Generation Improvements</u>

Edison points out that as additional non-dispatchable QF capacity is added to its system there is a need for increased flexibility in dispatching its other resources. In recognition of this problem Edison's resource plan addresses six possible solutions:

1. Shift on-peak demand to off-peak.
2. Reduce the minimum generation output.
3. Purchase peaking power.
4. Storage of off-peak energy for use on-peak.
5. QF dispatchability
6. Shift off-peak production to on-peak.

Of the six items Edison has only requested funding in this proceeding for items 1 and 2. Item 1, programs which shift on-peak demand to off-peak, are addressed in the demand side management section of this decision. Item 2 is the only item with which PSD's resource witness takes issue.

Edison has requested $4.2 million in test year 1988 to reduce its minimum operating load for certain oil and gas generating units. In addition, it capitalized $15.1 million in 1986 and expects to incur a like amount in 1989; both for reducing the minimum operating load. The following table details the units which Edison has modified and proposes to modify and the cost of modification.

<u>Units Planned for a Reduction in the Minimum Generation Output</u>
(Dollars in Thousands)

Unit		Completion Date (MW)	Capacity Reduction	Cost
Ormond Beach	2	1986	200	$15,050.0
	1	1989	200	15,050.0
Alamitos	5	1988	50	652.3
	6	1988	50	652.3
Redondo Beach	7	1988	50	652.3
	8	1988	50	652.3
Hunington Beach	2	1988		395.0
	1	1988		595.0
Mandalay	2	1988		595.0
	1	1989		595.0

Edison proposes to reduce the minimum generation capability at the Ormand Beach, Alamitos, and Redondo Beach units by making plant modifications. At the Huntington Beach and Mandalay units Edison proposes to go from three daily operating shifts to two, two-shifting, with the unit shut down during the third shift.

After performing cost-effective analyzes on Edison's proposed projects, PSD concluded that only the Ormand Beach unit 2 project is cost-effective. PSD recommends that the costs for minimum generation improvement at Ormond Beach unit 2 and an experimental two-shifting project at Huntington Beach unit 2 be allowed. For all other projects, PSD recommends no rate recovery in this proceeding, but that Edison consider a separate application or review in an attrition proceeding to present these projects when it has the requisite information to support them.

Edison's major concern with PSD's recommendations is not the need for further justification, but recovering its costs in a timely fashion. Since Edison bears the burden of proving the cost-effectiveness of these expenditures, its cost recovery is mainly within its control. We will adopt PSD's recommendation because it provides ample opportunity for Edison to receive timely ratemaking treatment on the expenditures it can justify to be cost-effective.

E. Sylmar-Pacific High Voltage Direct Current Intertie Expansion Project (DC Expansion)

In its application Edison has included $104.6 million in estimated plant additions for the DC Expansion. This project is a major augmentation of the existing high voltage DC line which connects southern California with the PNW. Once completed, the DC Expansion would increase the transfer capability for power between California and the PNW by 1030 MW.

The DC Expansion is a joint venture of Edison and LADWP. Edison's 50% share is on behalf of itself, PG&E, and SDG&E. To date Edison has spent approximately $4 million. A portion of the $4 million has been paid for engineering and construction services as part of a $70 million fixed price contract with Brown-Boveri. If Edison were to withdraw form the project it would remain responsible for one-half of its 50% interest in that agreement, or approximately $17.5 million. The project is currently under construction and is expected to be completed by December 1988.

This was the most actively debated issue in the resource planning area. The source of the controversey was the assumptions used to evaluate the project's cost-effectiveness. As a result PSD developed its own cost-effectiveness analysis and concluded that Edison should not participate in the project.

Edison takes the position that the DC Expansion is a cost-effective project and the lowest cost alternative to securing additional transmission capacity to the PNW. To evaluate the cost-effectiveness Edison used a decision analysis model or "decision tree" in which one or more alternative values for each of the input assumptions are placed in the computer model, weighted by the respective probabilities of their occurrence. The output of the model is a range of possible benefits with a probability assigned to each. Only capital related items are included in the cost calculations. Expenses are treated as a reduction to benefits.

The decision analysis evaluation Edison performed shows the present value of expected benefits of 729 different sensitivities to be $206 million. As a result of this analysis Edison believes that the estimated cost of $104.6 million is unquestionably prudent and that the project should be pursued to the benefit of its ratepayers.

While PSD does not take issue with the use of a decision tree, it identified some problems with the way Edison set up its model:

1. The model was biased by using a nominal carrying charge rate to levelize the capital costs associated with the project's avoided capacity. In its cost of service study, used to develop marginal costs for revenue allocation, rate design, QF payments and evaluation of conservation and load management programs, Edison used a real carrying charge rate.

2. The model does not properly account for the reduced benefit of taking capacity during the summer only, instead of all year.

3. Edison's current excess capacity situation was not taken into consideration. In valuing capacity from QFs, Edison applied an energy reliability index (ERI) to reflect the relative value based on its need for capacity.

PSD's analysis used a LOTUS spreadsheet to compute annual costs and benefits over the project's 30 year life (1989-2018.) A real carrying charge rate was applied to Edison's share of the project costs to get a stream of levelized payments analogous to the real cost of renting the line. Annual operation and maintenance costs were added to get a stream of total costs.

PSD ran a base case and 11 scenarios which tested sensitivities to changes in the critical variables, including ERIs, capacity prices, capacity availability in summer only and all year, duration of purchases, quantities of economy energy and Edison's avoided energy cost.

The net present values for the base case are negative \$171.1 million (capacity all year) and negative \$100.8 million (capacity summer only). The corresponding benefit to cost ratios are 0.09 and 0.46 respectively. All of the scenarios have net present values that are negative and benefit to cost ratios that are less than one.

While it does not recommend the use of PSD's cost-effectiveness analysis, Edison disagrees with some of the assumptions used and has calculated their impact on PSD's present value estimate. The following table summarizes these assumption differences:

Effect of Edison's Assumptions on PSD's Cost-Effective Analysis

	Assumptions	Change in Rate Base* (Dollars in Millions)
1.	Value of Summer Only Capacity - Edison 97%; PSD 72%	$ 9
2.	Full Value of PNW Capacity - Edison 1993; PSD 1997	5
3.	PNW Capacity Availability - Edison Throughout Project Life; PSD Ending In 1996	36
4.	Gas Prices - Edison Average Prices; PSD Marginal Prices	14
5.	Value of Purchased Energy	10
6.	BPA Economy Energy Price	13
7.	Forecasted Gas Prices	40
	Total	$127

* Assumes benefit to cost ratio of 1.0.

1. Assumption Differences

a. Value of Summer Only Capacity

Edison claims that PSD chose the wrong marginal demand cost allocation for summer only capacity by using the allocation factor for transmission and primary distribution in stead of generation. PSD's allocation factor assumes that capacity is coming from a single generating unit rather than the entire PNW system. In addition, Edison believes that PSD incorrectly used the on-peak factor to apply to the value of the combustion turbine. Edison recommends using the sum of the on-peak and mid-peak allocation factors since these reflect the amount of combustion turbine capacity that would be deferred.

As a result of these differences Edison's allocation factor for summer only capacity is 0.97 as compared to PSD's factor of 0.72. PSD's present value calculation would increase by $9 million if Edison's 0.97 allocation factor were used.

b. Value of PNW Capacity

In determining the value of excess capacity PSD included the Big Creek Expansion Project, the California-Oregon Transmission Project, and unfunded energy management projects. These amount to approximately 1,400 MW of peaking resource additions. Edison argues that these resources are either not funded or not under construction and should be removed in determining the capacity value factor.

If these peaking resources are removed capacity would receive full value in 1993 rather than 1997 as estimated by PSD. This would increase PSD's present value calculation by $5 million.

c. PNW Capacity Availability

PSD assumed that PNW firm capacity would be available to California only through 1997. This was based on PSD's view that:

1. Bonneville Power Authority's (BPA) most recent resource plan would require PNW utilities to commit running combustion turbines, old, small, inefficient oil, gas and diesel generators, and interrupting load as needed to direct service industries, primarily aluminum industries.

2. The proposed Long-Term Intertie Access Policy of BPA limits capacity exports on the intertie (including the DC Expansion) to 2550 MW, even when the intertie will be 6300 MW (5500 MW firm).

3. The conservation programs included in BPA's resource plan would have less than the 66% capacity factor assumed by BPA.

4. BPA's resource plan shows that the PNW will have limited capacity for firm sales to California by the planning year 2003-2004.

Edison disagrees with PSD's conclusion and believes that there will be sufficient surplus summer capacity available to fill the alternating current (AC) intertie, AC intertie uprate, DC intertie, and DC Expansion well into the 21st century. In arriving at this conclusion Edison relied on the resource plans of BPA and the Northwest Power Planning Council and the March 1987 Northwest Regional Forecast of the Pacific Northwest Utilities Conference Committee. Edison's interpretation of these forecasts indicates a need beyond 1997 for additional capacity to serve the PNW winter load, thus resulting in additional surplus summer capacity.

The difference between PSD's and Edison's estimate of available surplus summer capacity is $36 million based on PSD's analysis.

d. Gas Prices

PSD used Edison's marginal gas price in its analysis to evaluate the DC Expansion's cost-effectiveness against other resource options. The marginal gas price PSD used represents the Tier II rate that Edison pays SoCal.

Currently Edison pays SoCal on a fixed monthly demand charge and a declining block Tier I/Tier II commodity rate. Based on the adopted sales forecast in SoCal's recent consolidated adjustment mechanism decision, D.87-01-046, the current Tier I quantity is about 18% of Edison's total purchases from SoCal. The volumes Edison is billed at the higher Tier I rates is adjusted periodically based on Edison's purchases.

Edison recommends using its average gas price because it better reflects this linkage between Tier I and Tier II and is used as the basis for QF energy payments.

If average gas prices are substituted for marginal prices PSD's present value analysis would increase by $14 million.

e. Value of Purchased Energy

PSD did not time differentiate the value of energy purchased over the DC intertie. Edison believes this fails to recognize that the majority of the energy is expected to be purchased during the on-peak and mid-peak time periods. To properly reflect the value of the energy at the time received Edison suggests that the incremental energy rates (IERs) used in determining utility payments for QF energy be applied. Edison estimates that using PSD's IERs would increase the present value of PSD's cost-effectiveness analysis by $10 million.

f. BPA Economy Energy Price

PSD's analysis assumed economy energy costs were 21.8 mills/kwh in 1989. However, Edison points out this is in sharp conflict with PSD's Exhibits 60 and 60-A, marginal cost, where it recommends a price of 18 mills/kwh in 1988. Edison considers PSD's latter estimate of 18 mills/kwh more appropriate because it better reflects the historical relationship of economy energy prices being 60% of Edison's avoided energy price (natural gas).

PSD believes that the price of economy energy should be based on the BPA proposed rate cap formula to be consistent with current price behavior under BPA's Intertie Access Policy. It is PSD's view that the overall objective of BPA is to maximize its revenues on sales to California. To support this view PSD cites testimony in Edison's ECAC A.87-02-019 which refers to BPA's increased rates and spilled water to avoid producing electricity for sale to California.

The difference between PSD's 18 and 21.8 mills/kWh price for BPA's economy energy sales impacts PSD's analysis by $13 million.

g. Forecasted Gas Prices

PSD forecasted gas prices using the projected cost of low sulfur waxy residue (LSWR), No. 6 fuel oil. A 1986 price of $12.50/barrel for Singapore fuel oil was used as PSD's base price. Following adjustments for sales tax, shipping cost, and import tax, PSD applied a growth rate of 5 percent until 1991. After 1997 PSD used the CEC's 1986 real growth rate forecast and gross national product (GNP) implicit price deflation.

Edison's major concern with PSD's forecast is its low starting point. This yields a forecast for 1990 of $15.35/barrel which is considerably below the postings for Singapore LSWR of between $16.60 and $17.70 for the first part of this year.

Edison, in its analysis using the PSD computer spreadsheet, evaluated the present value benefits of using both the CEC ER-6, moderate price forecast as well as the Edison projection used in its August 1986 decision analysis evaluation of the DC Expansion. Use of these forecasts resulted in the present value benefits of the DC Expansion being increased by $32 million for the CEC forecast and by $40 million for the Edison forecast.

2. Discussion

The testimony in this proceeding clearly shows that Edison intended to participate in the DC Expansion project with or without our approval. By letter dated August 27, 1986 Edison stated that:

> "...we do not believe a Certificate of Public Convenience and Necessity is required for this upgrade....We have also accepted the responsibility and attendant risk, of demonstrating the reasonableness of our investment in the appropriate rate case at the time the expanded HVDC facilities become operational." (Emphasis added.)

Edison's actions involving the DC Expansion cause us deep concern. First, Edison's preliminary estimate of the project's costs as provided to PSD was $55 million. This estimate was considered to be incomplete and revised to $104 million a year later. Second, Edison steadfastly refused to file a CPCN stating that the project was only an upgrade and that there was not adequate time to process a CPCN and construct the facilities to meet a BPA completion date. Third, Edison informed the PSD that the reasonableness of project expenditures would be demonstrated after the project became operational. However, Edison neglected to tell PSD that it would request ratemaking treatment prior to the operational date. Finally, before Edison's general rate case application it justified the cost-effectiveness of the DC Expansion to PSD based on the the availability of BPA economy energy. In this proceeding Edison has premised the need for the project primarily on the availability of firm capacity.

PU section 1102 Code (Ch. 1430, Stats. of 1986) states that:

> "...an electrical corporation proposing to construct an electrical transmission line to the northwestern United States shall provide the Commission with sufficient reliable information that the proposed line...will be cost-effective."

PSD is responsible for analyzing all projects affected by PU Section 1102 and providing independent recommendations for our consideration. While PSD diligently attempted to fulfill its responsibilities, we believe Edison's efforts in providing PSD the most complete and reliable information available were less than exemplary.

Although this decision does not address the issue of when CPCNs are required, we caution Edison and other electric utilities that in the future we will expect a complete showing justifying the cost-effectiveness of similar projects prior to their receiving ratemaking consideration. In addition, utilities will be expected to cooperate with PSD to ensure that a utility's showing meets the minimum requirements of a CPCN application. This procedure should be similar to that used for NOI filings, i.e., deficiencies identified by PSD and corrected by the utility before acceptance.

The critical issue involving the DC Expansion project is the appropriate ratemaking treatment to be afforded Edison's expenditures. Edison has included $104.6 million in plant-in-service for this project and its cost-effectiveness analysis yields a present value of $206 million. PSD based on its cost-effectiveness analysis recommends that Edison be limited to recognition of an investment no greater than $47.8 million irrespective of the actual expenditures.

As previously discussed Edison believes that a CPCN is not required for this project, but is requesting ratemaking treatment prior to completion. For us to address Edison's request we must determine what is an appropriate amount to be included in rates. This requires a determination of the cost-effectiveness of this project as performed in CPCN proceedings. Additionally, PSD recommends that a cap be placed on the amount to be included in rates as required in CPCN applications. We concur with PSD's recommendation.

We are encouraged that Edison is using more sophisticated modeling techniques such as the decision tree model used in its showing here. Any model, however, is only as good as the assumptions upon which it is based. In this regard, we put all parties on notice that in cost-effectiveness calculations it is inappropriate to use a nominal carrying charge rate, to account for seasonal differences in capacity values, and to recognize existing excess capacity circumstances.

Since Edison has quantified its differences with PSD's cost-effectiveness assumptions, we will use PSD's analysis to determine an appropriate ratemaking value to be placed on the DC Expansion. The following discussion will address each PSD assumption which Edison contests.

a. & e. Value of Summer Only Capacity and Purchased Energy

Edison disagrees with PSD's lack of time differentiating the value of energy purchased and capacity received over the DC intertie. We believe it is appropriate to reflect the value of energy and capacity by time of day. This is done in rate design with time-of-use rates and with QF energy payments. Time differentiating energy and capacity will increase PSD's analysis by $19 million.

b. & c. Value and Availability of PNW Capacity

PSD, in valuing PNW capacity, has included 1400 MW of peaking resource additions which are not funded or not under construction, but excluded similar uncertain capacity in determining the availability of PNW capacity. We agree with PSD that a conservative approach should be taken with respect to capacity availability, but find its approach is inconsistent in its treatment of capacity resources. We believe that the cost-effectiveness analysis will be consistent in its assessment of expected capacity by excluding 1400 MW in valuing capacity. This will increase PSD's analysis by $5 million.

d. Gas Prices

In evaluating the DC Expansion PSD used Edison's marginal gas price as opposed to its average gas price. Although Edison's marginal gas price does not represent its true avoided cost under SoCal's current rate structure, our evaluation of this project is on a long run basis. Over the long-term we expect the rate structures under consideration for the gas industry will result in Edison's incremental gas purchases priced at the margin. We will use PSD's marginal gas prices for analyzing the cost-effectiveness of the DC Expansion project.

f. BPA Economy Energy Price

We agree with PSD that the price of BPA's economy energy should be 85% of Edison's avoided energy price to be consistent with BPA's current price behavior under its Intertie Access Policy. No change in PSD's cost-effectiveness analysis is warranted.

g. Forecasted Gas Prices

PSD's forecasted gas prices are based on the 1986 price of LSWR. While 1987 has seen a considerable increase in LSWR prices, it is not unusual to see large fluctuations in these prices over a short time period. Because of this and the wide divergence in projected gas prices we will average PSD's and Edison's forecasts. This results in a $20 million increase in PSD's present value of the DC Expansion.

As a result of the adjustments to PSD's assumptions listed above the draft decision found the break even rate base of the DC Expansion was $91.8 million. Subsequent analysis indicates that there may be some interactive effects that could lower this figure. Consequently, we will authorize Edison to rate base the actual cost for Edison's share of the project or $80.0 million, whichever is lower. Whatever the amount, ratemaking treatment will not become effective until the DC Expansion is operational and will be subject to refund pending a reasonableness review. These items are addressed in more detail in the section that discusses PU Section 463.

On November 23, 1987 PSD filed a motion to set aside submission with respect to the high voltage DC terminal expansion project and to compel production of documents. PSD states that Edison has failed to disclose the existence of various agreements, including a December 2, 1985 letter agreement with LADWP, that significantly alter the anticipated usage of several transmission projects including the DC Expansion project. Since Edison's anticipated usage of these projects is pivotal in establishing its need for and the cost-effectiveness of the projects, the withheld information has a significant bearing on whether the projects should be pursued.

In the case of the DC Expansion project the PSD requests that it be withdrawn from the submitted test year 1988 general rate case and be consolidated with any subsequent consideration of the Devers-Palo Verde transmission line No. 2. PSD's request for consolidation is based on Edison/LADWP agreements which link the two projects and the need to consider transmission projects together so that their interrelationships can be assessed.

In response to PSD's motion Edison argues that the letter agreement dated December 2, 1985 was merely a letter in which the parties expressed their intent to work toward a definitive agreement at a later time. Additionally, Edison states that: (1) it is not necessary to set aside submission of the DC Expansion project to protect the interest of ratepayers, (2) there is no final agreement to consider, (3) Edison and LADWP agreed that the proposed agreement will not be disclosed to third parties, and (4) without Commission authorization PSD cannot compel production of the proposed agreement.

Although we share PSD's concerns that information may exist which could have a bearing on the cost-effectiveness of the DC Expansion project, we do not find it necessary to remove this project from Edison's general rate case. However, Edison is put on notice that we intend to give further consideration to the cost-effectiveness evaluation adopted in this decision in conjunction with our analysis of Edison's other transmission projects and/or agreements with LADWP. The cost-effectiveness cap placed on the DC upgrade by this decision is for the upgrade presented to us by the utility. If the agreements called to our attention by the staff motion affect the nature and use of the upgrade, the cost-effectiveness cap will have to be redetermined in the new context.

The cost-effective amount of investment in the DC Upgrade is an issue to be litigated in Edison's application for a CPCN to construct the Devers-Palo Verde line. Edison should be aware that the amount of investment ultimately found to be reasonable may not exceed the amount of investment determined to be cost-effective in the context of the Devers-Palo Verde proceeding. Should our subsequent cost-effectiveness review yield different results, we will adjust the DC Expansion cap adopted in this decision. Finally, we consider our further review of the DC Expansion cap appropriate because Edison has freely assumed the risk of building this project without a CPCN and two years ago signed a letter agreement with LADWP which could impact the cost-effectiveness of the DC Expansion and other transmission projects without informing this Commission or our staff.

PSD's motion to set aside submission of the DC Expansion project is denied. However, we will grant PSD's motion to compel Edison to produce the documents requested in attachment 6 to the motion. Edison will be required to respond to PSD's data requests contained in attachment 6 within 10 days from the effective date of this decision.

F. <u>Treatment of Certain Plant Items Pursuant to PU Section 463</u>

On March 2, 1987, PSD filed a motion requesting that Edison be ordered to amend its Application to exclude all costs associated with uncompleted capital projects in excess of $50 million. Specifically, PSD moved that Edison be required to file separate applications in order to seek rate relief for four projects: Balsam Meadow hydroelectric generating plant, Devers-Valley-Serrano 500 KV transmission line, DC Expansion, and SONGS 1 capital additions in connection with the integrated living schedule (ILS). PSD's motion was based on the argument that PU Section 463 precludes consideration of uncompleted capital projects in excess of $50 million in future test year rate proceedings. Edison filed a response to PSD's motion, on March 16, 1987, arguing that the requirements of PU Section 463 are compatible with future test year ratemaking and that post-operational reasonableness reviews can be made in a subsequent general rate case proceeding.

On May 5, 1987, ALJ Ferraro issued a ruling denying PSD's motion, finding that PU Section 463 does not require a reasonableness review prior to establishing rates for capital projects or restrict the Commission from setting rates for capital projects on a prospective basis. In that ruling Edison and PSD were directed to develop, for inclusion in the rate case plan for this and future Edison general rate cases, a detailed procedure which would allow for the continuance of the Commission's traditional ratemaking process with respect to the projects addressed in PSD's motion. Attached as Appendix A is the proposed procedure jointly submitted by Edison and PSD.

The proposed procedure provides for modification of the existing MAAC to include recorded investment-related revenue requirement and the recorded revenues related to specific plant additions estimated to cost more than $50 million. Investment-related revenue requirement is defined as the sum of (1) depreciation; (2) ad valorem taxes; (3) taxes based on income, including any appropriate tax adjustments; and (4) return on CPUC jurisdictional rate base as set forth in the applicable tariff.

Edison and PSD propose that the procedure apply when plant is to be reflected in rates for the first time, and is eligible for inclusion in MAAC. Specifically, PSD and Edison propose that:

1. Plant additions to be included in MAAC be determined through the general rate case proceeding.

2. In-service criteria for each project to be included in MAAC be determined in the general rate case proceeding.

3. The initial investment-related revenue requirement and resultant MAAC rates for each project be determined in the general rate case proceeding, the initial MAAC rate level be equal to 75% of the revenue requirement, and the revenue requirement reflect the utility's estimated investment-related costs or the Commission's adopted cost cap level, whichever is less.

4. Noninvestment-related expenses associated with each project be determined in the general rate case and reflected in base rates through the general rate case.

5. A separate advice letter filing be made to place each project into the MAAC on or after its in-service date.

6. Previously determined MAAC rate changes for a project be implemented at the next regularly scheduled ECAC or base rate level change after its in-service date to minimize the number of rate changes occurring during the year.

7. Between the in-service date of a project and the implementation of MAAC rates reflecting that project, all recorded investment-related revenue requirement associated with that project be recorded as an undercollection in the MAAC balancing account pursuant to MAAC procedures. After implementation of MAAC rates both the recorded revenue and recorded investment-related revenue requirement be reflected in the MAAC balancing account.

8. The ultimately adopted reasonable level of investment for each project be reflected in rates pursuant to an application filed to establish the reasonable and prudent level of recorded costs of the completed project. Such applications should be filed no later than six months after the final portion of each project is placed in-service.

For this general rate case Edison and PSD propose that MAAC rate level increases, equal to 75% of the annualized revenue requirement, be authorized for each of four projects. These projects together with their estimated in-service date, project cost, and annualized revenue requirement are listed below:

Project	Projected Initial In-Service Date	Project* Cost	Annualized# Revenue Requirement
		(Dollars in Thousands)	
1. Balsam Meadow Hydroelectric Generating Project	December 1, 1987	$284,655	$ 47,636
2. Devers-Valley-Serrano 500 kV T/L	July 22, 1987	127,819	25,923
3. DC Expansion	December 31, 1988	80,000	15,903
4. Devers-Palo Verde No. 2 Transmission Line	June 1, 1990	207,952	39,121

* First year's rate base on date eligible for inclusion in MAAC.
\# 100% of CPUC jurisdictional revenue requirement.

The difference in the revenue requirements shown above and those contained in Appendix A reflects the adopted cost of capital and other revenue requirement items contained in this decision.

Additionally, PSD and Edison agreed that the SONGS 1 ILS, which comprises many numerous distinct and individual projects, should not be subject to this procedure, but should instead be reflected in base rates through the normal general rate case procedure in the same manner as other plant additions which cost less than $50 million.

We adopt the criteria set forth in the joint PSD/Edison Exhibit 203, Appendix A, for implementing PU Section 463. Our only modifications are to reflect the revenue requirement factors adopted in this decision and the fact that the Devers-Valley-Serrano and Balsam Meadow projects are presently in-service.

In Exhibits 240 and 241 Edison requested that the ratemaking treatment discussed above be implemented for the Devers-Valley-Serrano and Balsam Meadow projects. Based on these exhibits we conclude that the Devers-Valley-Serrano project was placed into service on July 22, 1987 and the Balsam Meadow project was placed in service on December 1, 1987. Additionally, both these projects meet the criteria set forth in Exhibit 203 and adopted above. As previously discussed the initial MAAC rate for PU Section 463 projects will be set at 75% of the project's revenue requirement. For the Devers-Valley-Serrano and the Balsam Meadow projects we will increase Edison's MAAC rate by $55.3 million or 0.085 cents/kWh which equates to 75% of the CPUC jurisdictional investment-related revenue requirement.

Finally, Edison in its comments raised the issue of the impact of the Financial Accounting Standards Board statement 92, Regulated Enterprises - Accounting for Phase-in Plans, impact on Exhibit 203. Since the only impact would be of an accounting nature, we will leave this issue open to be addressed in the future.

G. Research, Development and Demonstration

Edison has requested authorization of $40.1 million (1986 dollars) in test year 1988 funding for its RD&D plan. This represents approximately a 10% reduction from the authorized level of funding for 1986.

As proposed by Edison the RD&D plan consists of 12 programs grouped under six research areas. These areas are intended to correspond to the RD&D objectives and guidelines established in D.82-12-005. Edison's research areas and programs are outlined in the table below. All amounts in this section are in 1986 dollars.

Edison's 1988 RD&D Plan

Research Area	Programs
1. System Operations and Efficiency Improvements	1. Load Control/Customer Interface
	2. Storage and Energy Management Technologies
	3. Facilities Conversion for Optimal Operation
2. Advanced Energy Technologies	4. Competing for the Customer
	5. Advanced Energy Conversion
	6. Long Range/High Pay-back Technologies
3. Health and Safety	7. Occupational and Community Safety
4. Renewable Energy Resources	8. Renewable Energy Conversion
5. Environmental Improvement	9. Air Quality Enhancement
	10. Natural Resources Management
6. Energy Conservation and Efficient Resource Utilization	11. Customer Energy Management
	12. Alternate Fuels

1. PSD's Position

After reviewing Edison's RD&D plan, PSD believes that the competing for the customer program and the electric transportation project are diametrically opposed to the guidelines. These are described as follows:

a. Competing for the Customer

Total Energy Facilities - determine the feasibility of Edison becoming a total energy supplier both near existing generating stations and also to complexes requiring a central energy supply located away from existing generating stations.

<u>Advanced Space Conditioning</u> - work toward increasing the efficiency of space conditioning equipment and providing customers with cost-effective options for shifting electric space cooling loads from on-peak to off-peak periods.

<u>On-Site Generation and Cogeneration Project</u> - explore and develop various small generating technologies which can provide an alternative to traditional electric service.

b. Storage and Energy Management Technologies

<u>Electric Transportation</u> - accelerate development of commercial electrically powered transportation involving prototype vehicle evaluations, development and evaluation of advanced vehicle/battery concepts, formulation of commercialization strategy, and electrified roadway demonstrations.

PSD states that these are marketing programs designed to develop additional sales, build load, and to avoid losing sales to self-generation. PSD believes that marketing and load building programs are very short-sighted and, while they take advantage of current excess capacity, promote usage that ultimately needs to be curtailed. In addition, PSD is concerned that Edison's use of ratepayer monies for the development of these programs will primarily benefit its investors, either through the utility company or its unregulated subsidiaries. Finally, PSD argues that Edison's participation in the electric transportation project should be through the Electric Power Research Institute (EPRI), since it will be doing work of a parallel nature.

Another area in which PSD recommends a reduction in Edison's budget is the high performance peaking technologies project. PSD recommends that Edison's budget for this project be cut by $225,000 by combining the monitoring research activities.

PSD also disagrees with Edison's shift in priorities from developing new resources to consuming existing conventional resources at an expanding rate. Edison reduced its original budget for the alternate fuels, occupational and community safety, and advanced energy conversion programs by $2.4 million and other programs by $2.5 million. These reductions were made to provide funding for the competing for the customer and load control/customer interface programs and the electric transportation project without increasing the overall RD&D budget. PSD recommends reinstatement of $1.5 million in program cuts for the alternate fuels, occupational and community safety, and advanced energy conversion programs.

The following table summarizes Edison's and PSD's recommended RD&D program expenditures.

Comparison of Edison and PSD RD&D Expenditures
(1986 Dollars)

Program Area	Edison	PSD	Edison Exceeds PSD
	(Dollars in Thousands)		
1. Load Control/ Customer Interface	$5,075	$5,075	$ 0
2. Competing for the Customer	2,540	0	2,540
3. Storage & Energy Management Technologies	3,005	2,005	1,000
4. Customer Energy Management	3,700	3,700	0
5. Alternate Fuels	1,175	1,850	(675)
6. Air Quality Enhancement	2,000	2,000	0
7. Facilities Conversion for Optimal Operation	1,750	1,750	0
8. Renewable Energy Conversion	1,180	1,180	0
9. Occupational & Community Safety	1,000	1,550	(550)
10. Advanced Energy Conversion	500	525	(25)
11. Natural Resources Management	500	500	0
12. Long Range/High Pay-back Technologies	475	475	0
Research Support/ EPRI	17,227	17,227	0
Total	$40,127	$37,837	$2,290

Besides its differences with Edison on specific RD&D programs, PSD has addressed four policy issues: (1) ratepayer benefits from EPRI dues, (2) approval of RD&D program changes in excess of $500,000, (3) establishment of a one way balancing account for RD&D funds, (4) coordination of large RD&D programs with other California utilities, and (5) inclusion of all RD&D expenses in the same account.

While PSD has accepted Edison's request for full funding of EPRI dues, it is concerned about EPRI's apparent shift in research direction and whether ratepayer benefits from EPRI exceed contributions. First, PSD recommends that Edison in its next general rate case be required to provide a comprehensive assessment of the benefits from EPRI. Second, PSD is concerned that the labels (creating the future, building markets, reducing risks, and controlling costs) used by EPRI for its program expenditures for 1987-1989 seem to indicate a shift in research direction. This leads PSD to recommend that if a single proceeding is established to investigate all utility RD&D programs EPRI, its orientation, and ratepayer benefits should be included.

Next, PSD states that it does not wish to deter Edison from making shifts in its RD&D budget and priorities when appropriate. However, PSD believes that it and the Commission should be given sufficient information to allow oversight of Edison's decisions. Because PSD feels that it was not provided detailed information concerning shifts in Edison's RD&D budget and priorities (see discussion below), it recommends that Edison receive approval before shifting funds. Specifically, PSD proposes that an advice letter procedure be required to shift funds between programs in excess of $500,000 or 50% of the budget, whichever is less. In addition, PSD recommends that a one way balancing account be imposed to insure that RD&D funding is spent on RD&D projects.

PSD is also concerned with the amount of coordination among California utilities in their RD&D efforts. While PSD

strongly supports our statements in D.87-07-021 that there is a need to ensure that RD&D is coordinated and cost-effective to ratepayers, its recommendation in this proceeding is that Edison avail itself of existing opportunities for coordination.

Therefore, PSD recommends that effective January 1, 1989, Edison not be permitted to undertake large demonstration projects (exceeding $5 million on an aggregate rather than annual basis) having statewide benefits without presenting evidence that it was reviewed by the California Utility Research Council (Council). Although this is not intended to give the Council a veto over these projects, PSD states that Edison should receive an endorsement from the Council.

PSD's last policy issue concerns Edison's accounting practices for RD&D expenses. To simplify record keeping PSD recommends that all RD&D expenses be accounted for in Edison's A&G account 930.2.

As a final item, PSD has expressed considerable displeasure with Edison's handling of program revisions. PSD argues that after Edison's application was filed it made dramatic changes in the RD&D program without informing the Commission or the PSD, except in a cursory fashion. Because of this, PSD claims that it was unable to make a detailed review of the recent modifications. PSD states that after Edison's witness testified that he could not think of any other significant changes in the RD&D budget, Edison less than three weeks later filed new testmony that:

1. Added an entirely new program area called competing for the customer which was given the second highest priority and a budget of $2.5 million.

2. Decreased the storage and energy management technologies program by $1.5 million.

3. Reduced the alternate fuels program by $1.1 million.

4. Reduced the renewable energy conversion program by $570,000.

In addition, PSD points out that less than 24 hours prior to Edison's witness testifying to these revisions, PSD received additional prepared testimony concerning a multi-year, multi-million dollar program to develop an electric vehicle. PSD does not believe there is any reason for Edison's actions and, in fact, is unaware of any other area in this general rate case where major updates were not provided well in advance.

2. **The Organizing Committee for the California Institute for Energy Efficiency's (Institute) Position**

The Institute is proposed as a university-based research institution with participation by California utilities, our Commission, the CEC, and others. The Council has reviewed a number of Institute-proposed projects for medium-to long-term, end-use research with statewide significance. These would be co-funded by California utilities, State agencies, and others. While not an active participant in the proceeding, the Institute did file a brief. The following summarizes its position as contained in that brief:

1. There is a need for increased utility emphasis on long-term, end-use RD&D that is consistent with the utility's resource plan and coordinated with other California utilities and experienced research organizations.

2. The Institute is an appropriate mechanism for implementing the objectives above.

3. Edison should be authorized and encouraged to participate in the Institute, as part of its RD&D and related energy management and end-use load research activities, at a minimum level of $1 million to $2 million per year.

3. <u>Edison's Position</u>

In support of its competing for the customer program Edison states that in late 1986 it acted to refocus the direction of its research programs to provide customers with a better value for their energy dollar. Greater emphasis is now being placed on technologies that will help customers reduce their energy bills through improved efficiency. Through this program Edison proposes to:

1. Provide existing customers with cost effective technologies to shift a portion of their load from peak to off-peak periods to take advantage of lower time-of-use rates.

2. Operate the existing generating stations at higher loads and efficiencies resulting in lower costs to existing customers.

3. Develop high efficiency, low cost on site generators which contributes to the CEC's goal of greater efficiency and cost stability and could result in substantial royalty revenues being flowed through to ratepayers.

Edison justifies its electric transportation project by stating that it will improve system load factor, reduce the amount of economy energy rejected at minimum load, and increase the operating efficiency of Edison's generating units. In addition, Edison estimates that with the technology that could be achieved in the next three years (150-mile vehicle range), its off-peak load would increase by 600 MW compared to its 2000 MW of excess base load during minimum load conditions. This, Edison argues, will help stabilize electric rates and benefit all customers, not just the owners of electric vehicles.

The last project which PSD opposes is in the area of high performance peaking technologies. Edison points out that this project involves the transfer of information on new technologies to other Edison departments and the monitoring or keeping abreast of other research organizations, is cost-effective and eliminates duplication. Edison believes that PSD's recommendation to combine monitoring efforts of different technologies to reduce cost is cosmetic; the activity must still be performed by the research scientist with expertise in the individual technology.

Finally, on the issue of program funding, Edison agrees with PSD's position that $1.5 million in funding for the alternate fuels, occupational and community safety, and advanced energy conversion programs should be restored.

In response to the policy issues that were raised by PSD and the Institute, Edison states that:

1. It has consistently adopted a research budget equal to or greater than the authorized Commission funding for RD&D and intends to use funds committed to RD&D on RD&D projects.

2. All future RD&D expenditures will be accounted for in A&G account 930.2.

3. It has participated in a review of the Institute's proposed projects through the Council and that some of these projects will receive funding. However, the Institute's recommendation is inconsistent with Edison's competitive bidding policies.

4. Discussion

PSD criticizes the competing for the customer program and the electric transportation project because they are marketing and load building programs, primarily intended to benefit Edison's investors. Because PSD was not provided sufficient time to review these programs, we feel the true benefits of providing customers with the opportunity to shift loads and reduce their overall energy bills were overlooked. This coupled with Edison's ability to operate its generating stations at higher loads and efficiencies justifies these types of programs.

While Edison's proposed budget for the competing for the customer program should be authorized, we feel that the electric transportation project should not be approved as requested. Edison has not demonstrated that this project is unique for Edison or, more importantly, that similar benefits cannot be obtained from EPRI, which is performing work of a parallel nature. However, we will authorize Edison to include $100,000 in its budget to monitor the work of EPRI and other organizations in this area.

PSD's other program funding recommendations concern the high performance peaking technologies project and the alternate fuels, occupational and community safety, and advanced energy conversion programs. With respect to the high performance peaking technologies project, we find Edison's justification satisfactory and will not cut its budgeted amount.

For the remaining programs at issue, both PSD and Edison recommend that $1.5 million be restored to Edison's RD&D budget. Edison made these cuts to partially offset increases in other areas. Our review of the alternate fuels, occupational and community safety, and advanced energy conversion programs indicates that they are generally beneficial to the ratepayers. Because these are lower priority programs we will authorize Edison to restore only $900,000 in funding for these three programs.

At ALJ Ferraro's direction Edison was permitted to revise its RD&D showing to reflect the electric transportation project, but not allowed to increase its overall budget request from that contained in its application. As a result of this ruling, Edison identified the occupational and community safety and natural resources management programs as the lowest priority and reduced their budget commensurate with the increase for the electric transportation project. Since neither Edison or PSD made a recommendation with respect to the natural resources management program, we will not restore funding for this low priority program.

Finally, consistent with prior general rate decisions for Edison and other energy utilities, we will reflect Edison's actual billing for EPRI dues of $14.7 million. This is an increase of approximately $247,000 over Edison's estimated dues for 1988.

The next area we will address is the policy issues raised by the parties. In D.87-07-021 we expressed our interest in pursuing a generic proceeding that would consider the merits of all energy utility RD&D programs on a consolidated basis. In R.87-10-013 we directed Edison, SoCal, PG&E, and SDG&E to comment on the establishment of a generic proceeding for approval of all RD&D budgets. While it will take time to fully coordinate the budgets of these utilities, EPRI, and the Gas Research Institute (GRI), the benefits of a more cost-effective RD&D program should be well worth the effort.

Currently the four major energy utilities that we regulate spend nearly $100 million annually on RD&D programs, including dues to EPRI and GRI. Since this is a significant expenditure of ratepayer funds we believe that a simultaneous review of each utility's RD&D program will reduce duplication, provide uniform policy direction, and increase the cost-effectiveness of utility run RD&D programs as well as EPRI and GRI benefits.

Although a consolidated proceeding will provide the mechanism through which these accomplishments can be made, it in itself is not the solution. For us to have a record from which to direct the utilities, it is necessary to have an organization such as the Council assist us. The Council was created in response to P.U. Sections 9201 through 9203. These code sections require us and the CEC to meet annually with representatives from the four energy utilities named above. In addition, representatives of municipal utilities, public utility districts, EPRI, GRI, and consumer or ratepayer organizations may be invited. As stated in P.U. Section 9203:

> "The purpose of the meeting shall be to work towards achieving all of the following goals:
> (a) Promoting consistency of research, development, and demonstration programs with state energy policy.
> (b) Preventing unnecessary duplicative research, development, and demonstration efforts.
> (c) Where appropriate, freely exchanging information related to research, development, and demonstration projects.
> (d) Identifying opportunities for joint funding of research, development, and demonstration projects."

With this mandate from the legislature we expect that the Council will develop a report which addresses the items listed above and can be used in our generic proceeding as a guide to establish each utility's RD&D budget. It is not our intent to control the Council or give it control over the RD&D budgets we authorize, but rather to work with the Council to insure that RD&D expenditures are made in the best interest of utility ratepayers.

To accomplish this we will direct Edison, SoCal, PG&E, SDG&E, and PSD to work toward the objectives outlined above. In addition, we expect Edison, SoCal, PG&E, and SDG&E to set forth in their future RD&D budget requests how their proposed budgets meet the guidelines established in prior Commission decisions and the objectives of the Council. We want to emphasize that we are committed to this coordination effort and expect the utilities and PSD to inform us of any problems which would impede its implementation.

With the establishment of R.87-10-013 we will not adopt PSD's recommendation requiring Edison to receive approval of program changes. However, Edison will be held accountable in either the generic proceeding or its next general rate case, whichever comes first, for any changes made in its RD&D programs. All expenditures for program changes found unreasonable will be deleted from the one-way balancing account retroactively.

With respect to the funding of Institute programs, the Commission is in favor of allocating $1 million to ensure that funding is provided in the interim, before resolution of the generic RD&D proceedings. We expect the Institute to become an active participant in the generic RD&D proceeding in seeking future funds. In the interim we encourage Edison to coordinate its end-use research activities with other utilities and Institute, and emphasize that we may review the administration of such activities. Because Edison has in the past allocated RD&D contracts without competitive bidding, we perceive no barrier to its contracting with Institute. We also expect Edison to work with the Institute in resolving any difficulities surrounding Edison's competitive bidding policies for RD&D.

We also feel that in light of the generic RD&D proceeding it is premature for us to address specific recommendations concerning coordination of RD&D programs and benefits from EPRI dues.

The last policy issues which were raised concern PSD's recommendations to establish a one way balancing for RD&D funds and to record all RD&D expenses in account 930.2. Because of the unique nature of RD&D, we will adopt a one way balancing account for Edison to insure that RD&D funds are spent on RD&D programs. This is consistent with our discussion in D.87-07-021 in which a one way balancing account was adopted for PG&E. Additionally, to facilitate the analysis of RD&D expenditures, we will adopt PSD's recommendation that all RD&D expenses be accounted for in Edison's A&G account 930.2.

Finally, while Edison's presentation in this proceeding was generally very professional, we consider part of its conduct in the RD&D area unacceptable.

At the Pomona public hearings Edison in its opening statement proposed a new multi-year, multi-million dollar electric transportation project. While it was thoughtful of Edison to inform the public of its new program, the public hearings were not the proper time or place to initiate such a request. Not only does the rate case plan not provide for this type of presentation at public hearings, but Edison had just revised its RD&D budget seven days earlier without any mention of the electric transportation project. Edison is put on notice that it should take steps to insure that this does not reoccur and that any future late additions or substantial changes will simply not be considered.

H. Productivity

A new area which has been addressed in recent general rate cases is the use of econometric models to measure the productivity for total utility operating expenses. These models relate changes in a utility's level of production, to changes in the level of required resources. The percentage change in the productivity index from one period to the next measures the savings due to productivity.

Both Edison and PSD developed econometric models to evaluate the the productivity savings contained in Edison's test year operating expense level. Edison, based on its total factor productivity (TFP) model, determined that no adjustment to its requested expense level was warranted. PSD concluded from its multi-factor productivity model that Edison's requested operating expense should be reduced by $211.5 million to adequately reflect productivity savings.

Edison's model estimated productivity for the historical period 1976-1985 and the projected years 1986-1988. Over the 13 year study period, Edison's TFP index increased at an average rate of 1.6% per year as compared to the annual rate of more than 2% reflected in Edison's test year expense. Although Edison believes that the TFP index confirms the reasonableness of its test year operating expense, Edison states that it is an inexact measure of performance. Other factors besides productivity affect the year to year change in the index, such as variations in the availability of hydro power. Additionally, Edison argues that a productivity index should not be used as a rate case adjustment mechanism because it double counts productivity gains and is applied to only one segment of utility costs, operating expense.

Because a productivity index measures productivity already embedded in Edison's rate case cost estimates, Edison states that any adjustment to expense based on an index will be double-counting. Next, Edison points out that over the past decade, in response to higher fossil fuel prices, it has moved from a reliance on conventional oil and gas fired generation to the use of a variety of technologies, including nuclear, hydroelectric, and renewable energy sources. Because the index shows overall productivity gains, no consideration is given to the fact that fuel savings outweigh the increased use of capital and labor. Accordingly, it is inappropriate to apply a utility-wide measure to only one segment of costs such as operating expense, since productivity savings do not occur evenly.

Edison is critical of PSD's productivity model for the reasons stated above and because it is difficult to interpret, exceedingly complex, subject to error, and does not account for changes in Edison's operating environment. Also, Edison believes that PSD's use of the ECAC fuel and purchased power forecast to determine operating expense from its model is inappropriate. PSD's model predicts fuel and purchased power will be 54% of variable costs in 1988 as compared to 58% for recorded 1986, but Edison states that PSD chose to use the ECAC forecast which is 64% of variable costs.

Finally, Edison claims that PSD's recommendation is not plausible and creates a perverse incentive. First, PSD's econometric forecast results in an unrealistically low level of O&M expense. The O&M expense recommendation of PSD is $122 million below actual 1986 and significantly lower than the expense estimates of PSD's results of operation witnesses. Second, the more productive a utility has been historically, the greater the reduction in the recommended level of operating expense. A utility which has been productive will receive less money to operate than a utility which has been less or not productive.

In developing its model PSD investigated the historical relationship between five input variables (fuel, purchased power, capital, labor, and materials) and Edison's output (kilowatthour sales). The relationship between the changes of the inputs and the changes of the output over the historical period defined Edison's historical productivity and formed the basis for PSD's projection of productivity in the test period. PSD observed an annual productivity growth over the recorded period of 2.4% and projected a productivity growth of 3.4% for 1988. Based on its projected productivity growth, PSD recommends that Edison's requested O&M expense be reduced by an additional $115.8 million over the recommendations of PSD's results of operation witnesses.

Finally, after analyzing Edison's TFP model PSD concluded that with some minor refinements it is the same model used by PSD in PG&E's general rate case and rejected in D.86-12-095.

In arriving at a reasonable level of operating expense for utilities we typically consider productivity gains due to changes in technology, economies of scale, and improved efficiency. However, it is difficult to quantify the impact these have in the test year. While individual witnesses for Edison and PSD, depending on their estimating methodology, either directly or indirectly reflected productivity gains in their test year estimates, until recently no attempt was made to determine how these compared to recorded productivity gains for total operating expense. The productivity models of Edison and PSD do this by analyzing recorded productivity gains in order to forecast productivity gains in the test year.

Edison concluded from its TFP analysis that its requested operating expense level reflected historical productivity gains and should be adopted. PSD's analysis led it to recommend an additional $115.8 million reduction in Edison's requested level of operating expense. Compared to Edison's original O&M expense level request of $1,374 million PSD's recommended operating expense level, including its productivity adjustment, reflects additional productivity gains of $317 million.

We feel that a comparison of recorded versus projected productivity gains is useful. However, due to the complexities in and the divergent results of the models their application will be limited to determining a range of productivity gains to be adopted in the test year. As defined by these models, the range is between 1.6% and 3.4% or a net range of 1.8%. Since our adopted operating expense level of $1,205 million without a productivity adjustment incorporates productivity gains of 2.56%, approximately the middle of the range, we will increase it to a level of 2.70%. This adjustment is an additional .14% reduction. When .14% is compared to the 1.8% range, it is equivalent to .08 of that range. Since the range is equivalent to $317 million, our .14% adjustment results in an additional reduction in Edison's operating expenses of $24.7 million. We believe this is warranted to put Edison in a posture to respond to an increasing level of competition.

I. Employee Compensation

As part of its review of Edison's results of operations, PSD performed an analysis of Edison's employee compensation levels. Based on this study PSD determined that administrative, professional, and supervisory (APS) employees are paid 10.2 percent over the prevailing market and that Edison's ratemaking payroll expense should be reduced by $19.7 million.

PSD's recommendation was developed from a variety of employee compensation surveys and related data obtained from Edison. The two key surveys used in PSD's evaluation of APS salaries were Edison's 1986 APS salary survey conducted by Organization Resource Counsellors, Inc. and SoCal's 1986 survey of executive, administrative, professional an supervisory positions, conducted by Sibson & Company, Inc..

Edison objects to PSD's use of these surveys for a number of reasons:

1. The surveys were designed 15 years ago for the purpose of tracking labor market salary movement.

2. The same jobs that were included in the original surveys are still used even though many are now vacant and certain areas are not represented.

3. Sample sizes contained in the surveys are too limited, introducing the potential for bias.

4. Data from nine of the companies is common to both surveys.

Additionally, Edison argues that PSD's analysis contains significant technical errors which render its conclusions invalid, and inappropriate as the basis for an adjustment of estimated payroll expense. Edison identifies the following as errors in PSD's analysis:

1. The impact of employee turnover, which involves such considerations as stability of the work force, average experience level, individual employee performance, seniority, and Edison's investment in training and development, is ignored.

2. PSD did not consider the affects compensation levels have on Edison's ability to attract qualified and experienced employees.

3. The nature of Edison's organization, its size, the characteristics of its service territory, its customer mix, and the

methods used to provide service were not included.

4. PSD failed to evaluate the relationship between APS pay levels and pay levels for bargaining unit employees.

5. The survey data was improperly weighted.

While Edison did not attempt to evaluate employee compensation based on salary surveys, it did make a comparison of payroll to revenue. This approach provides a quick indicator of overall payroll costs relative to a selected marketplace or industry. Using the 1986 executive compensation survey conducted annually by Sibson & Company, Inc., Edison concluded that for 108 companies the average percentage of payroll to revenues is 12.44% which compares favorably to Edison's 12.07%.

Edison also adjusted PSD's analysis to correct for the improper weighting of jobs and the double counting of companies. PSD's overpayment of APS employees is reduced from 9.2% to 7.5% based on Edison's calculations.

Finally, Edison cites D.86-12-095 for PG&E in which management salary levels exceeded the utility industry average by approximately 8% as recognition that paying a small premium over market benefits the ratepayer as well as the shareholder.

In support of its recommendation, PSD states that its study of employee compensation focused on the market from which Edison draws it labor, categorized payroll data by type of employee, and relied on five independent salary surveys. PSD grouped Edison's work force into five categories: (1) executive, (2) APS, (3) clerical, (4) physical, and (5) technical. PSD found Edison's executive, clerical and physical salaries to be reasonably in accord with market salary levels, and did not recommend an expense reduction for those categories. Since there was insufficient data available for Edison's technical work force, PSD made no ratemaking recommendation for that category. For APS employees, although a benefit comparison was not made, PSD concluded that salary levels are excessive and recommended a 9.2% or $19.7 million reduction in labor expense for this category.

In concluding, PSD states that it is puzzled by Edison's argument that the salary surveys used by PSD are inappropriate for evaluating the reasonableness of compensation to APS employees. PSD wonders why these salary surveys are commissioned if they should not be used to study salaries.

We believe PSD's analysis in this proceeding is a significant improvement over its PG&E proposal. However, before it can be used to judge the reasonableness of Edison's level of payroll expenses, there are further refinements that should be considered. First, comparisons should either be made on a total compensation basis or adjusted to reflect the employees' benefit package. Since employees choose employment opportunities on a total compensation basis, we consider it reasonable to judge utility compensation in the same manner. Second, in addition to point comparisons based on averages information indicating the range of data should be provided. Lastly, Edison's criticisms concerning sample sizes and the duplication of jobs and companies in the survey data should be addressed.

Our objective is to ensure that ratepayers are not burdened with paying for employee compensation levels beyond that which is necessary for Edison to provide safe reliable service at reasonable rates. This type of evaluation is difficult because of the subjectiveness involved in quantifying the variables used. To minimize this, we expect both PSD and Edison in future general rate proceedings to develop an agreed upon data base for judging the reasonableness of employee compensation levels. For this proceeding, we find Edison's justification for its APS compensation levels reasonable.

J. <u>Affiliated Transactions</u>

PSD raised five issues concerning the affiliated relationships of Edison and its subsidiary companies. In this proceeding Edison and PSD have come to agreement on two of these issues: gains on sales of utility assets to affiliates and net income of utility-related subsidiaries. For these issues Edison and PSD recommend that:

1. All gains on sales of utility assets to nonutility subsidiaries should be recorded above-the-line at market value.

2. Utility-related subsidiaries should be treated, for ratemaking purposes, as utility departments and all transfers of utility assets to those subsidiaries should be at book value.

3. Net income from utility-related subsidiaries should be recorded above-the-line.

Edison and PSD are also in agreement that a $1.0 million increase in Edison's test year estimate of other operating revenues should be adopted to reflect the impact of these recommendations.

PSD's remaining three issues address royalty payments from subsidiaries. For these issues PSD recommends that subsidiaries pay:

1. A royalty or affiliate payment of 5% of gross revenues.

2. A markup of 10% for services provided by the utility.

3. A royalty upon the transfer of an employee from the utility to the subsidiary equal to 50% of the employee's annual salary.

The three issues above were also addressed in A.87-05-007, Edison's request to establish a holding company structure. In A.87-05-007 Edison and PSD submitted a joint exhibit agreeing to: (1) the markup royalty for services provided by the utility and (2) the guidelines for utility employee transfers to affiliates. As stated in the joint exhibit a 5% markup on fully loaded labor costs will be billed to nonutility affiliates for the use of Edison employees. The joint exhibit also sets forth the following guidelines for the transfer of utility employees to affiliates:

1. The staffing of the nonregulated affiliates will not be to the detriment of utility operations.

2. In instances where it may be desirable to move an Edison employee to an unregulated affiliate, senior management approval of both companies involved in the transfer will be required before the transfer can occur.

3. Edison employees will be free to accept or reject employment with the unregulated affiliates and no involuntary transfers will take place.

4. If an Edison employee elects to accept a position with an unregulated affiliate, he or she will be required to resign from Edison.

5. Edison will provide to the Commission an annual report identifying nonclerical personnel transferred from Edison to the Holding Company or any of the nonutility subsidiaries.

We find the agreement between Edison and PSD applicable in resolving these same issues in Edison's general rate case. As a result of the agreement we will increase Edison's other operating revenues by $70,000 for the test year.

Finally, we note that A.87-05-007 also addresses the royalty to be paid by affiliates on gross revenues. Accordingly, we will not consider that issue in this decision.

K. Hazardous Waste Management

Edison and PSD were the only two parties that addressed this issue. Edison had requested $10.1 million annually for three years for its hazardous waste program and $11.7 in capital expenditures for its underground storage tank program. After reviewing Edison's hazardous waste management proposal PSD introduced Exhibit 65-A which recommended a number of changes in Edison's request. Since Edison has stipulated to PSD's recommendations, we will adopt them with some minor modifications concerning reporting dates and the inclusion of hazardous waste sites other than manufactured gas. The adopted recommendations are detailed below:

1. Edison should file an application for funding prior to expending funds when its hazardous waste program for the sites it owns is more definite. Applications under this procedure are only intended for hazardous waste cleanup at sites included in Edison's general rate case filing and/or in its annual hazardous waste management report.

2. For hazardous waste sites that Edison does not currently own, it should file an application to receive prospective funding for remedial investigations or work when Edison is ordered by a regulatory agency or a court to perform such work or is notified by a regulatory agency that it is considered a potentially responsible party for these costs.

3. Upon approval Edison should be allowed to place actual program costs into a memorandum account for recovery in a subsequent ECAC or general rate case proceeding. This account should accrue interest at the ECAC interest rate.

4. No retroactive recovery of hazardous waste costs incurred prior to 1988 should be authorized.

5. Edison should file with the Executive Director and the PSD's Resources Branch a comprehensive overview of Edison's hazardous waste management effort, including its underground storage program, by March 31, 1988 and update it annually by January 31 until ordered otherwise.

6. $1 million of Edison's requested budget for mitigating contamination from underground storage tanks should be redirected to the alternate technologies described in Exhibit 65-A.

We will adopt Edison's requested funding level for the underground storage program as agreed to by PSD. Funding for the investigation and clean up of hazardous waste sites will be deferred until Edison files an application(s) as discussed above. A description of the information which Edison should include in its application(s) and annual filings is detailed in Exhibit 65-A.

L. Female/Minority Business Enterprises

Edison implemented its F/MBE program in 1979 to identify F/MBE suppliers and provide them with increased opportunities to participate in Edison's procurement activities. Since that time by D.82-12-101, our generic investigation of utilities' employment practices, and D.84-12-068, Edison's 1985 general rate case, Edison's F/MBE program has been expanded and modified to include reporting requirements. Currently, Edison's reporting requirements include the development of a data collection system to track F/MBE program results by ethnic classifications, annual goal setting, and demonstration of significant progress in the dollar amounts and number of F/MBE contacts awarded.

R.87-02-026, dated February 11, 1987, was initiated in response to PU Sections 8281-8296. This rulemaking proceeding will address long-term goal setting, verification procedures, and annual reporting. Accordingly, Edison's general rate decision will focus only on program funding requirements and past performance in compliance with D.84-12-068.

In addition to Edison's presentation, PSD and American G.I. Forum; Filipino American Political Association (Public Advocates) made recommendations concerning Edison's F/MBE program.

1. Program Funding

Edison requests $636,390 to fund its F/MBE program for test year 1988. As proposed, its budget includes the annual salaries of one F/MBE administrator, one clerk, and eight analysts. This funding level is intended to maintain Edison's F/MBE data base, verify the status of F/MBE firms, and set targets in over 800 procurement categories and nine ethnic/gender classifications. Edison uses the targets to participate in outreach activities and arrive at annual goals for commodities, services, and construction. Although Edison's proposed F/MBE budget does not specifically include funding to comply with PU Sections 8281-8296, Edison believes it is necessary not only to maintain the current program, but to respond to current and future program demands, including requirements associated with PU Sections 8281-8296.

PSD recommends a budget of $505,544. PSD's lower budget level is due to a reduction of $20,000 for certification and the exclusion of two analysts. Public Advocates has not made a recommendation concerning Edison's program funding level.

2. Performance

D.84-12-068 directed Edison to submit specific information relative to its F/MBE program and demonstrate that it had achieved significant progress in the dollar amounts and number of F/MBE contracts awarded. Exhibit 10 contains Edison's compliance with D.84-12-068. While no party claims that Edison has not complied with D.84-12-068, Public Advocates claims that Edison has made no progress in furthering the development of F/MBE's.

In support of its claim Public Advocates cites Edison's performance over the last three years of less than 4.5% of all contract amounts to F/MBEs and less than 0.3% to blacks. Public Advocates states that Edison has not achieved significant progress in the awarding of contracts to F/MBEs and recommends that:

1. Top executive compensation be tied directly to F/MBE achievement.

2. Substantial long range goals be set.

3. Edison be penalized by requiring that a sum equal to one-half of 1% of its total outside contracts in 1986 ($5 million) be allocated to assisting in direct F/MBE development.

4. Edison be admonished for its poor record.

5. This case be treated separately from R.87-02-026.

6. Edison develop a program to encourage and facilitate joint ventures, develop mechanisms to improve equity and capital sources for minority and women entrepreneurs, and assist F/MBEs in acquiring insurance coverage at favorable rates.

7. A category for Filipino-Americans be included in Edison's F/MBE data collection.

8. Contract awards be reported by service/purchase type.

Additionally, Public Advocates argues that Edison's outreach program has not addressed the inability of F/MBEs to be competitive with white contractors and top management has shown a lack of interest in the F/MBE program.

In spite of Public Advocates' desires to deal with all F/MBE issues in general rate cases we will reaffirm our intentions to address only specific F/MBE program matters in general rate cases. Accordingly, items 1,2,5,7 and 8 will be addressed in R.87-02-026. The remaining items are discussed below.

The record demonstrates that Edison increased its dollar awards to F/MBEs from $38.3 million in 1984 to $74.8 million in 1986 and increased the number of awards from 3,805 to 5,025 for the same period. By any measure this was a significant increase for this period. Although these numbers pale in comparison to Edison's total awards, Edison has complied with D.84-12-068 and we will not adopt Public Advocates' recommendations contained in items 3 and 4 above. However, we are not satisfied with the level of F/MBE participation and expect Edison to achieve substantial and significant increases in the number and amount of awards to each major ethnic group and for women.

We agree with Public Advocates that more can be done to assist F/MBEs in successfully competing for Edison contracts. To accomplish this Edison should develop a program which encourages and facilitates even greater participation of F/MBEs in Edison contracts through joint ventures and through assistance to F/MBEs in meeting financing and insurance coverage at rates competitive with Edison's non-F/MBE contractors. We will increase Edison's requested funding to $700,000 for test year 1988 to implement this expanded F/MBE program and we expect to see the fruit of this enhanced funding in future proceedings.

VI. Demand Side Management

A. Introduction

Demand Side Management (DSM) refers to ratepayer funded programs undertaken by the utility to affect customer energy consumption patterns. Over the years our funding of such conservation and load management programs has tracked the availability and price of energy resources. Thus, in the 1970's, when fossil fuels were at a costly premium, we embarked on a course of approving and funding a number of conservation programs. We further stated that it was our intention to make the vigor, imagination, and effectiveness of a utility's conservation efforts a key question in future rate proceedings. (D.84902, 78 CPUC 638 at 746 (1975).)

At that time, we also made clear our reliance on marginal cost principles in assessing the need for conservation programs. Specifically, we observed: "Where the marginal cost of conserved energy is less than the marginal cost of new supply the former should always be the investment of choice." (D.91107, 2 CPUC 2d 596 at 706 (1979).)

More recently, we have reduced our emphasis on large and often costly conservation programs in the face of changing economic and resource conditions impacting the utilities which we regulate. For Edison, these changes, similar to those being experienced by other utilities, have included the following: (1) greater stability in the utility's financial condition, (2) embedded costs above marginal costs due to dramatic decreases in the price of oil and gas, and (3) an excess of available capacity over the next several years due to the completion of large baseload plants and the successful development of qualifying facility resources.

In light of these changes, we have adhered to a policy of "staying the course" with respect to conservation and load management program development and funding. With D.86-12-095 in

PG&E's most recent general rate case, we reduced program funding below previous levels. In taking this action, supported by our lessened concerns regarding supply availability and price, however, we also recognized that future needs required that conservation and load management programs continue in place as a valuable long-term resource. PG&E, PSD, and all other parties were encouraged to continue to evaluate demand-side programs on an equal footing with new supplies. (Id., at p. 94.)

In addition to the influence which a utility's available resources have in determining the level of conservation program funding, the Commission has also recently recognized the need to consider the effects on such programs of competition in the field of electric generation. The competition on which the Commission has focused comes in the form of "bypass," a situation in which the customer chooses to generate its own energy rather than accept the service available from the local public utility.

This phenomenon, of particular concern to the Commission when the self-generation is "uneconomic," has been addressed in a separate section of this decision. However, the Commission's recent decision on this issue in its 3-R's (Risk, Return, and Ratemaking) Rulemaking (R.86-10-001) adopted policies designed to address the problems created by bypass. (D.87-05-071.) Among these policies is one which directly impacts our evaluation of funding for DSM programs.

Specifically, the Commission concluded that the Electric Revenue Adjustment Mechanism (ERAM) should be eliminated for the large light and power class. In D.87-05-071, we found that the risks which ERAM had been intended to neutralize (i.e., instability in interest rates, high rate of inflation, and poor utility financial health) had diminished. Further, we concluded that its elimination for the large power class would create a greater incentive for the utility to maximize revenues from that class and thereby more effectively respond to emerging competition.

The utilities and interested parties had noted, however, that ERAM had allowed the utilities to pursue conservation, load management and social programs required by the Commission without working directly against the utilities' own interests. Despite this circumstance, we concluded that the most cost-effective conservation programs should still be retained in the large light and power class. We also noted that since our decision on ERAM did not impact the commercial and residential classes, the utilities' incentives to pursue effective conservation for those classes remained unchanged.

D.87-05-071 also included our recognition that many short-term conservation programs might not now be cost-effective due to changing economic and resource conditions. We found, however, that this conclusion was not to be seen as a weakening of our commitment to conservation and load management programs. As stated in D.87-05-071, "[w]e firmly believe long-range conservation is still very important, and utilities should continue to promote reasonable conservation and efficiency options to their customers." (Id., at p. 4.) We noted in particular that when a new factory or new production process is designed, "ignoring energy efficiency would be short-sighted." (Id.) We admonished the utilities, however, to refrain from using ratepayer funds for utility marketing programs aimed at increasing utility profits when ERAM is eliminated.

B. Basic Positions on DSM Funding

In its application, Edison had originally requested for 1988 a funding level of $69.8 million for DSM programs. In March, 1987, this amount was reduced to $60.3 million. In response to Edison's request, the Public Staff Division (PSD) proposed an overall DSM budget of $47 million. As the following table illustrates, funding levels for direct program expenses are the source of the most significant differences between the Edison request and the PSD recommendation.

Edison/PSD 1988 Overall Demand-Side Management Program Expenses Comparison
(Thousands of 1985 Dollars)

Description	Edison	PSD	Variance
Residential Conservation	$17,061	$15,679	$(1,382
Non-Residential Conservation	19,942	14,893	(5,049)
Load Management	12,253	5,456	(6,797)
Marketing	0	0	0
Measurement and Evaluation	6,600	7,325	725
Support Programs	4,784	3,528	(1,256)
Total DSM Programs	60,640	46,881	(13,759)
Adjust. for Program Emphasis	(350)	(350)	(0)
Grand Total DSM Programs	60,290	46,531	(13,759)

In addition to the issue of program funding, Edison and PSD also provided ratemaking and non-budgetary recommendations. These proposals focused on the consolidation of all DSM funds into base rates, the shifting of funds among programs, the handling of budget changes between rate cases, the funding of programs for customer groups removed from ERAM, the changing of reporting requirements, and the use of a consistent set of generic terms for program descriptions and reporting breakdowns.

Several parties offered testimony on both the Edison and PSD proposals. Among them were the California Energy Commission

(CEC), the California/Nevada Community Action Association (Cal-Neva), and the Thermal Energy Storage Manufacturers' and Contractors' Association (TESMAC). The CEC generally supports the funding levels proposed by Edison in the area of load management, and asserts, along with Edison and TESMAC, that the PSD has provided an overly broad definition of "marketing" in determining which programs may be funded through rates. The CEC also believes that its funding and cost-effectiveness recommendations have been appropriately based on examining Edison's long-term resource needs.

Both the Edison request and the PSD recommendation propose reduced DSM expenditures relative to recent levels. The differences in these proposals relate primarily to different interpretations of recent Commission decisions and utility trends. While Edison has basically made program-specific recommendations, PSD believes that current economic and resource conditions and D.87-05-071 require certain major changes to the entire DSM area.

Among other things, PSD recommends the elimination of DSM funding for the large light and power incentive programs and the elimination of ratepayer funding for any utility marketing program or programs with no potential ratepayer benefit. For this purpose, PSD has defined "marketing" programs as those programs which increase the use of at least one fuel (electricity or gas) relative to what would have happened in the absence of the program. PSD states that load retention, which PSD defines as the promotion of the installation of devices which utilize electricity instead of gas, should be considered marketing because resulting increased electric sales would not have existed in the absence of the program.

PSD also recommends that in the event the Commission authorizes any strategic marketing programs in this proceeding, participating customers be required to agree to "give up" or "return" something, e.g., become interruptible customers or

otherwise reduce their demands. It is PSD's overall view of marketing which was the source of much debate in this proceeding.

With respect to cost-effectiveness analysis, all parties generally used the tests established by joint CEC/CPUC staff publication known as the "Standard Practice for Cost-Benefit - Analysis of Conservation and Load Management Programs." The tests addressed in that guide include the utility, participant, non-participant, all ratepayer and societal perspectives. Edison did not take issue with certain PSD suggested nomenclature changes to the standard practice nor PSD's redefinition of the nonparticipant test as the rate impact test (RIM). Edison noted, however, that any such changes would be finalized as part of ongoing workshops on standard practice revisions.

While all parties were guided by the same standard, differences existed between Edison and PSD with respect to input assumptions and computation as well as the manner in which the tests were to be applied to the various programs. In evaluating these programs, PSD and the CEC agreed that greatest emphasis should be placed on the all ratepayer test which compares the total device costs to the benefits associated with marginal cost impacts. PSD and the CEC also concurred in using other test results, i.e., the RIM and participant tests, as a means of accounting for the cost-effectiveness implications measured by these tests, particularly equity considerations among customers. Edison stated that it placed priority on the all ratepayer test for informational, educational and survey type programs and the RIM test for programs involving incentives.

Despite the agreement between PSD and the CEC on applicable cost-effectiveness tests, PSD objects to the CEC's criticism that the PSD viewed load management and conservation programs in the short-term. PSD states that it did consider the long-run ramifications of the conservation and load management programs and that it evaluated the cost-effectiveness of these

programs on the same basis as it would other resource options available to Edison. PSD also expresses its concern regarding the CEC's failure to provide evidence of its own cost-effectiveness analysis in its testimony or in response to a PSD data request.

With respect to this final point raised by PSD, we note that while we greatly appreciate the CEC's participation in this case, it is necessary to address certain procedural flaws in the CEC's presentation in order to ensure the integrity of our rules. The first of these deficiencies relates to the CEC's failure to respond to a PSD data request for the results of its cost-effectiveness evaluation of the Thermal Energy Storage (TES) program. As we have stated in our discussion of marginal costs, parties relying on computer models and related data must provide this information for purposes of cross-examination and rebuttal. This requirement is based not only on statute (Cal.Pub.Util.Code, Section 1821, et al.), but is also dictated by the rules of fairness and due process. The CEC witness acknowledged its failure to provide this information, but indicated on the record during hearings on June 12, 1987, that the information would be provided "early next week." (Tr. at p. 4919.)

The CEC, however, never met this deadline and did not provide the information until after the filing dates for opening and reply briefs in this proceeding. When the information was finally provided to PSD on September 2, 1987, the cover letter revealed that in fact the CEC had relied on PSD's files and output, varying this information only to include a $500/kW installed cost for TES equipment and the PSD's proposed TOU-8 rate schedule. This representation, however, like the CEC's cost-effectiveness study, cannot be considered part of the record in this proceeding having been provided outside the context of the hearing and briefing process.

Another procedural issue related to the CEC's showing must also be noted. Specifically, the CEC was given an extension

of time beyond that offered to other parties to file its reply brief. Ethics and fairness dictate that an extension granted to one, but not all, parties to a proceeding may not be used as an opportunity to respond to briefs which were timely filed. This rule is particularly important in the general rate case setting in which numerous parties are involved and limited time is available. To protect the rights of every party, no party should be granted an advantage over another, and the parties' comments should end with a final, single reply brief.

In its reply brief, however, the CEC did in fact respond at length to the reply brief of PSD. The CEC's brief not only addresses PSD's reply brief in the main discussion, but then examines PSD's reply in a point-by-point analysis contained in an appendix. This approach goes beyond the limits of fairness and prevents our consideration of those portions of the CEC's reply brief directed to the PSD's reply brief.

C. Specific Programs

In this section each of the DSM programs is reviewed with respect to differences in funding requests and non-budgetary recommendations. For each program area, the parties' positions are summarized followed by our resolution of each of the issues presented and our approval of a specific funding level.

1. Residential Conservation

In the Residential Conservation category, Edison and PSD differ by approximately $1.4 million in their funding recommendations. The source of this difference are adjustments recommended by PSD in two areas: (1) Residential Information activities and (2) Energy Management Services. PSD has also proposed non-budgetary restrictions related to the Energy Efficient Home Builders' and the Direct Assistance Programs. The following table summarizes Edison's and PSD's proposals for residential conservation.

Residential Conservation
Edison/PSD Expenses Comparison
(Thousands of 1985 Dollars)

Description	Edison	PSD	Variance
Residential Conservation			
Residential Information	$ 2,626	$ 1,919	$(707)
Energy Management Services	4,149	3,474	(675)
Weather & Retrofit Incentives	768	768	0
Energy Eff. Home Builders	1,000	1,000	0
HP Water Heater/Solar Service	40	40	0
Appliance Eff. Incentives	4,105	4,105	0
Direct Assistance	4,373	4,373	0
Total Residential Conservation	17,061	15,679	(1,382)

a. Residential Information

Residential Information includes two programs: (1) the Energy Management Action Line and (2) Give Your Appliances the Afternoon Off. PSD recommends funding for Residential Information at $1,919,000, a $707,200 reduction from Edison's proposed funding level of $2,626,200.

With respect to the Energy Management Action Line, Edison asks that its funding request of $626,200 be approved. PSD, on the other hand, recommends that the budget be constrained to the 1986 recorded level of $454,000. Edison challenges PSD's recommendation on the grounds that, while no increase in calls is anticipated between 1987 and 1988, the calls will represent a significant increase over 1986. Further, Edison argues that despite call volume stability in 1987 and 1988, the calls will be longer and more complex requiring more operator time and training.

PSD responds, however, that it had already taken an expected increase in calls into account in making its recommendation. Additionally, PSD states that it accepted Edison's figures for call increases, even though prior historic experience indicated that a lower estimate was appropriate.

The record supports and we find reasonable PSD's recommended funding of $454,000 for Residential Information. PSD properly took into account both historic and anticipated call volume in making its recommendation.

With respect to the Give Your Appliances Off program, Edison believes that its proposed funding level of $2,000,000 is appropriate to reestablish and reinforce the load management message at a time when public awareness and concern for energy issues have diminished. PSD, however, recommends constraining funding for this program to the 1986 recorded level of $1,465,000. PSD notes that although Edison cites increasing media advertising costs as the justification for proposing a 37% funding increase, recorded 1985/1986 expenses and planned 1987 expenses reflect a decrease in funding requirements.

We again find reasonable and adopt PSD's $1,465,000 funding level for the Give Your Appliances Off program. This amount, based on historic and current funding levels, is sufficient to provide the information necessary to communicate the need and the manner in which residential customers can conserve energy.

b. Energy Management Services

In the category of Energy Management Services, PSD proposes a $674,857 or 16% reduction from the $4,148,600 funding level requested by Edison. This reduction is attributable to PSD's proposed funding for the Residential Energy Survey Program. Specifically, PSD recommends the elimination of Class A (on-site) surveys, the institution of a revised mix of survey options, and the limitation on the total number of audits to the 1986 recorded level of 60,000 as opposed to the 28% increase over that level recommended by Edison.

In support of its position, PSD states that costly Class A (in-home) audits are not required by either federal or state law. Should the CEC decide, as the result of current workshops, to require the Class A audit, PSD believes that Edison has sufficient

budget flexibility to accommodate any needed funding. It is also PSD's position that adequate information can be provided to the customer by a "do it yourself" Class B audit. PSD's notes that its recommendations provide Edison the opportunity to provide whatever direct personal assistance is required after that audit is completed. In PSD's opinion, with a well-developed self audit guide, the need for personal assistance should be the exception, not the general rule.

In response, it is Edison's position that it requires the flexibility to respond to customers who request an in-home survey because of the impact on residential customers which would result from the adoption of its proposed increased rates. In Edison's opinion, the Class A on-site survey is the only tool with the technical sophistication to give the customer an in-depth analysis of residential energy usage. Further, Edison notes that while PSD acknowledged that some on-site follow-up to the Class B survey would be necessary, no funding was recommended by PSD to account for this activity.

While we commend PSD for its cost-cutting efforts in the field of conservation, we do not agree that this area is one which should be a target for such restrictions. Not only can we not rule out the possibility that the Class A survey may be required by the CEC in the test year, but we believe that the need for the survey could escalate in the coming years as we move toward a revenue allocation based on Equal Percent of Marginal Cost (EPMC). As our discussion of revenue allocation indicates, the adoption of EPMC has the greatest impact in terms of increased rates on the residential customer. For this customer group, which does not have purchase or generation alternatives to accepting utility service, energy conservation is the only means by which the residential customer can control his utility bill.

As D.87-05-071 makes clear, despite changing needs for conservation programs for the large power class, the residential

and commercial customers still require effective means of altering or restricting their energy consumption. We therefore find that Edison's proposed funding level of $4,149,000 for Energy Management Services, which would maintain the current audit mix and include a reasonable increase in audits under the Residential Survey Program, is reasonable and should be adopted.

c. Weatherization and Retrofit Incentives

Edison accepted PSD's $768,000 budget recommendation for Weatherization and Retrofit Incentives. PSD's proposed limitation on funding for the Residential Energy Management Incentive Program to attic insulation, wall insulation, storm windows, and duct insulation is also appropriate. Further, PSD has properly targeted the non-coastal areas of Edison's service territory as the focus for Edison's promotional efforts for this program. We therefore find reasonable and adopt PSD's recommended funding level and program specifications for Weatherization and Retrofit Incentives.

d. Residential New Construction

Two programs are included in the category of Residential New Construction: the Energy Efficient Home Builders' Program and the Heat Pump Water Heater/Solar Service Agreements. Edison and PSD are in agreement on the funding levels of $1,000,000 for the home builders' program and $39,700 for the heat pump program. We find reasonable and adopt these funding levels.

Edison disagrees, however, with PSD's non-budgetary recommendation that funding be allowed for central electric heat pumps (a part of the Energy Efficient Home Builders' Program) only where natural gas is not available. Edison states that the program is designed to encourage the installation of high efficiency electrical equipment in a residence that has already been designed with electricity as the choice of fuel. Edison believes that it is in the best interests of all parties to encourage maximum energy efficiency regardless of the availability of other types of energy.

We concur with Edison and will not place the restriction proposed by PSD with respect to funding for central electric heat pumps. We do adopt, however, PSD's recommendation that funding not be extended to the heat pump water heater as this element of the home builders' program was found not to be cost-effective. We also follow PSD's suggestion to direct Edison to investigate lower incentives for this program. This direction, however, is applicable to all conservation and load management programs as we seek to ensure the application of ratepayer funds to only efficient and cost-effective programs.

e.. Appliance Efficiency Incentives

Edison accepted PSD's $4,105,000 budget recommendation for the Appliance Efficiency Incentives Program. Based on PSD's cost-effectiveness analysis, PSD has properly identified those program elements for which funding will apply (i.e., room air conditioners, evaporative coolers, central air conditioning, central heat pumps, and precoolers). PSD's recommendation restricting eligibility for central air conditioning rebates and for central heat pumps to customers with existing systems is also reasonable. We therefore find reasonable and adopt PSD's proposed funding and specifications for this program.

f. Residential Conservation Direct Assistance

Residential Conservation Direct Assistance is a program a part of which (the low income Energy Assistance Program) involves direct grants to low income customers for hardware installations. These installations include weatherization, evaporative coolers, replacement air conditioners, clock thermostats, portable heaters, and whole house fans. In this proceeding, while Edison accepted PSD's budget recommendation of $4,373,000 for the low income program, Cal-Neva, a statewide association of community action agencies, proposed a funding level of $5,470,000.

According to PSD, its recommendation was based on the funding of cost-effective elements, excluding the non-cost-effective portable heater from funding, and constraining the cost per measure to the levels adopted in the 1987 Conservation Load Management Adjustment Clause (D.87-05-021). PSD notes that D.87-05-021 resulted in establishing a $5.5 million budget for the low income program for 1987. PSD states, however, that this decision is not dispositive of the issue of funding in this proceeding. Specifically, PSD cites this Commission's statement in D.87-05-021 that the $5.5 million budget was "an equitable course" to take until our review of all of Edison's energy management programs in this proceeding. (D.87-05-021, at p. 24A.) PSD also believes that its proposed funding level for the Energy Assistance Program is properly proportioned to the program's all ratepayers test cost-effectiveness ratio of 2.0 which fell between the 2.10 for Appliance Efficiency Incentives and 1.64 for Weatherization and Retrofit Incentives.

Cal-Neva states that the funding which it has recommended for the Energy Assistance Program is based on the funding level approved for 1987 in D.87-05-021. Cal-Neva disputes PSD's, and Edison's recommendation to cut 20.1% from 1987 funding for test year 1988 and PSD's proposal to limit the cost per measure to 1986 levels. Cal-Neva asserts that this funding reduction was improperly based on the "parity" or proportion of the total of the residential DSM funds spent on low-income programs. According to Cal-Neva, the proper basis for determining the funding level for this program is not the percentage of funds spent on poor people, but rather the level of market saturation and cost-effectiveness.

In this regard, Cal-Neva states that only it presented direct evidence regarding market saturation. Cal-Neva states that its testimony indicates that only 140,000 of approximately 1 million low-income customers of Edison have been served by the

program, with market saturation not expected until 2016 at Edison's current rate of service.

Cal-Neva believes that the Energy Assistance Program is clearly needed to enable low-income customers to better manage their energy use at a time when the residential class may experience disproportionate bill increases due to the move to an EPMC revenue allocation. Further, Cal-Neva asserts that the cost-effectiveness of the program is beyond question and clearly exceeds that of the TES Program supported by Edison and the CEC.

Cal-Neva also asserts that the elimination of portable heaters from this program should not result in a funding reduction, but in a funding redirection to more cost-effective program elements. This approach, according to Cal-Neva, would permit more poor people to be served by the program. Cal-Neva also asks the Commission not to rely on currently non-existent federal grant money as a reason to cut either aggregate or per measure funding for low-income conservation.

Despite its acceptance of PSD's funding proposal for the Energy Assistance Program, Edison's statements in its opening brief appear to mirror Cal-Neva's concerns regarding the existence of federal funding for this program and in turn PSD's recommendation to constrain 1988 costs per measure to 1986 costs. Edison states that in 1986 it used a grant from the Federal Solar and Energy Conservation Bank to offset the cost of its direct installation program. According to Edison, the actual cost per conservation measure was actually higher than the costs reported to the Commission which reflected only Edison's costs and not the additional contributions made by grant funding. Edison states that

it has exhausted its grant funding and is not assured that additional funding of this type will be available in 1988.[2]

Edison therefore asks the Commission to allow Edison to negotiate individual costs per measure according to actual market value. If these costs are restricted to the 1986 level, Edison is concerned that available funds will be insufficient to provide targeted customers with a free installation.

As our previous statements indicate, we share Cal-Neva's desire to continue providing adequate funding for residential conservation programs which are cost-effective and will aid residential customers in coping with increased rates. We consider the Energy Assistance Program to be an important means to this end for that group of customers who are least able to absorb rate increases--low income residents.

We also concur with Cal-Neva that cost-effectiveness and market saturation are factors which should be accorded significant weight in determining funding levels. That level should therefore not just be determined by apportioning targeted funds between programs aimed at the same customer group on the basis of the cost-effectiveness rankings of those programs. We believe that the evidence in this proceeding supports a funding level for the Energy Assistance Program greater than that proposed by PSD. Specifically, the record reflects the high cost-effectiveness of the program, the lack of market saturation, the need for continued energy conservation by low income groups, the uncertainty of federal grants, and the questionable applicability of the 1986 cost per measure recommended by PSD in the absence of those grants.

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2 PSD states in its reply brief that it learned of Edison's concerns regarding the availability of federal funding for the first time in Edison's opening brief.

Based on this record, we find that it is reasonable to continue funding for the Energy Assistance Program at the level adopted in the 1987 Conservation/Load Management Adjustment Clause (CLMAC). For this program, we therefore adopt the funding level proposed by Cal-Neva of $5,470,000.

2. <u>Non-Residential Conservation</u>

The following table presents an itemized listing of the differences between Edison and PSD for non-residential conservation programs. The overall $5,049,000 difference relates primarily to PSD's recommended reduction for the New Construction (Award Building) program, but also includes PSD adjustments in the Non-Residential Information, Energy Management Service (Commercial), and Energy Management Incentives (Administrative) categories. Edison and PSD also disagree on the participation of large power customers in the commercial and industrial incentive programs. In this instance, this issue, however, did not affect funding.

Non-Residential Conservation
Edison/PSD Expenses Comparison
(Thousands of 1985 Dollars)

Description Non-Residential Conservation	Edison	PSD	Variance
Non-Residential Information	$ 1,110	$ 767	$ (343)
Energy Mgmt. Serv. (Commercial)	4,403	4,090	(313)
Energy Mgmt. Serv. (Industrial)	2,731	2,731	0
Energy Mgmt. Serv. (Agricultural)	1,208	1,208	0
Subtotal Non-Res. Services	9,452	8,796	656
EM Incentives (Commercial)-Small		1,912	
EM Incentives (Commercial)-Med.		1,534	
EM Incentives (Commercial)-Large		0	
Subtotal Comm. Incentives	3,446	3,446	0
EM Incentives (Ind.)-Small/Medium		1,227	
EM Incentives (Ind.)-Large		0	
Subtotal Ind. Incentives	1,227	1,227	0
EM Incentives (Admin.)	678	337	(341)
New Construction	5,139	1,087	(4,052)
Total Non-Residential Conservation	19,942	14,893	(5,049)

a. CIA Information

Edison's Non-Residential (Commercial/Industrial/Agricultural (CIA)) Information category is comprised of two programs: CIA Energy Management Outreach and the Major Accounts Representatives Program. Edison states that it considered 1986 expenditures to determine the appropriate overall funding level for this category of $1,109,900. Edison notes, however, that the Major Accounts Representative Program was in operation for only six months in 1986 and that expenses for this component were therefore increased to reflect a full year's activity.

PSD states that its recommended funding level of $767,000, $343,000 below Edison's request, still represents a 96%

increase over the 1985 authorized funding level. PSD also asserts that its proposal includes an increase in funding for the Major Accounts Representative element to reflect a full year of activity. However, PSD proposes a reduction in funding for CIA Energy Management Outreach to a level which PSD believes will be completely adequate, in conjunction with Edison's Energy Management Services Program, to cover the costs of providing information to Edison's CIA customers

We concur with PSD and find reasonable its recommended funding level for this category. PSD's proposal represents a substantial increase over the previously authorized level, takes into account a full year of activity under the Major Accounts Representative Program, and provides adequate funding for "outreach."

b. Energy Management Services

Edison proposes a funding total for all Non-Residential Energy Management Services of $8,341,590 as compared to PSD's recommendation of a $8,028,358 budget. The source of the difference in funding proposals relates to PSD's recommended reductions in the Small Commercial Energy Management Services budget. PSD bases its recommended reduction on an assumed cost per survey of $100, an amount based on the recent recorded average cost per survey.

Edison disagrees with PSD's proposal to limit the average cost-per-survey in this category to 1986 recorded levels. Edison states that in 1988 it plans to offer surveys at the same level as prior years, but only to those customers responding to Edison's survey offer. It is Edison's belief that those customers will be more likely to take action to implement the survey recommendations and that PSD's recommended funding will compromise Edison's ability to sufficiently administer this program.

We find that PSD's recommended funding for the Small Commercial Energy Management Services program based on recent

recorded costs is reasonable and should be adopted. Edison's statements regarding its proposed change in approach to offering the surveys does not appear to be one which will lead to any significant increase over current recorded costs.

c. Energy Management Incentives: (Commercial & Large Industrial)

Initially, Edison accepted PSD's funding recommendation of $1,227,000, for Non-Residential Energy Management Incentives, with incentives allocated between small, medium, and large power customers on the basis of load. While Edison still concurs with this funding level, it disagrees with PSD's subsequent decision, based on PSD's interpretation of D.87-05-071, to eliminate funding for the large commercial customers and to reallocate those funds to the small and medium customers.

Edison believes that PSD's exclusion of the large commercial customer (above 500 kw demand range) from this incentive program is based on a misinterpretation of D.87-05-071. Edison states that in D.87-05-071 the Commission indicated its intent to continue cost-effective conservation programs for large light and power customers. Further, Edison asserts that it is premature and unfair to define "large customers" as all TOU-8 customers. Edison notes that workshops are currently being held to implement the policies adopted in D.87-05-071 and that the definition of "large customer" has yet to be resolved.

We concur with Edison. Our intention in D.87-05-071, as we have indicated in our introduction to DSM, was not the complete elimination of all conservation programs for large power customers. Rather, our concern was that with the elimination of ERAM for the large power customer, the utilities would feel constrained to pursue such programs for these customers. To avoid this result, we specifically ordered that the most cost-effective programs be retained for the large power group. There has been no challenge in this proceeding to the cost-effectiveness of this incentive program

for the large commercial customer. Further, we have yet to adopt a definition, as Edison has indicated, of the large power customer, an issue properly resolved in the 3-R's Rulemaking. For these reasons, we believe that PSD's original funding recommendation, both as to the funding level and as to the allocation of those funds between small, medium, and large commercial customers, is reasonable and should be adopted.

d. Energy Management Incentives--Administration

For the administration of the Energy Management Incentives Program, Edison and PSD disagree on the appropriate funding level. Edison supports a budget of $0.68 million, while PSD recommends funds of $0.34 million. PSD's recommended adjustment of Edison's request is based on its corresponding adjustment of CIA incentives. PSD testified that the CIA administration level is directly related to the incentive level. PSD states that despite Edison's apparent denial of this correlation, its witness, on cross-examination, acknowledged that comparable percentage changes had occurred in incentives and administrative expenses between 1985 and 1986.

Edison, however, disputes PSD's assertions. According to Edison, although the incentive levels may have decreased over those originally proposed by Edison, its original estimate of costs to conduct program administration is still appropriate since the customer base qualifying for incentives will remain the same. In Edison's view, the costs of providing information and promoting the program are not altered by a decrease in the incentives level, and a change in that level does not result in a proportional change to administrative costs.

Despite Edison's stated position to the contrary, the record appears to support PSD's contention that there is a direct correlation between incentive levels and administrative costs. We therefore find reasonable and adopt PSD's proposed expense level of

$338,453 for the administration of the Energy Management Incentives Program.

e. Non-Residential New Construction

The category of Non-Residential New Construction includes programs designed to promote energy efficient buildings and appliances. Edison's and PSD's funding recommendations for this program are widely divergent. Specifically, Edison has requested funding of $5.1 million, while PSD recommends a reduction of this budget to $1.1 million.

PSD states that it developed its recommendation by conducting an historical analysis of the costs associated with this and other related programs and by determining the cost-effectiveness of the various elements. PSD states that for the Daylighting portion of this program PSD did not rely on the building standard requirements, but on the historical spending for the Daylighting element alone ($888,000 in 1986). For all other elements in this program area, PSD adopted a figure of $925,000 or 25% of Edison's proposed $3,700,000 for Other New Energy Management Measures. PSD notes that the significant element of the "Other" category is Space Conditioning which is marginally cost-effective.

PSD's recommendation also includes restricting the program to non-TOU-8 customers on the basis of PSD's interpretation of D.87-05-071. The result was to reduce the $1,813,000 originally resulting from PSD's analysis by 40% to PSD's proposed $1.1 million. PSD further recommends that eligibility for incentives for heat pumps be restricted to facilities located in areas where natural gas is unavailable. PSD acknowledges that while this restriction is not included in its testimony it is consistent with PSD's recommendations for Residential New Construction (Energy Efficient Home Builder) and Residential Appliance Efficiency Incentives.

Edison states that its proposal is needed to fund not only the Daylighting program included by PSD, but also Edison's

proposed Award Building Program in which the Daylighting program has been included. Edison states that the Award Building Program will encourage other energy management measures that increase the overall efficiency of new commercial/industrial buildings above state building standards.

Edison believes that PSD's recommendation is improperly based on historic spending for the Daylighting program, which would therefore exclude recognition of the Award Building Program, and on old building standards. Edison is also concerned that the funding reduction recommended by PSD will not fund the program at a level sufficient to influence commercial and industrial customers to "build-in" energy management technologies during the new construction process.

Edison further asserts that PSD has misinterpreted D.87-05-071 by limiting the program to non-TOU-8 customers and reducing the funding level by $725,200. Edison believes that it is incorrect to exclude TOU-8 customers from participation in this program which has been shown to be cost-effective.

In its reply brief, Edison strongly opposed PSD's introduction in its opening brief of its recommendation to exclude heat pumps from eligibility in the incentive program. Edison states that PSD improperly assumed that the construction practices and use of heat pumps are the same in the residential and non-residential sectors.

We note the legitimacy of many of the arguments which Edison has raised with respect to PSD's proposal. While PSD's approach may be consistent with historic spending and may take into consideration some funding for new programs, we are nevertheless concerned that adopting PSD's proposal may prevent Edison from achieving the legitimate and cost-effective goals of this program.

We also do not concur, as we have stated previously, with PSD's conclusion that D.87-05-071 requires the exclusion of TOU-8 customers from participation in DSM programs. The availability of

conservation programs to large power customers again depends on the cost-effectiveness and the need for the program with respect to that customer class. We believe that this program is one to which large power customers are entitled to participate.

We note that PSD's funding level inclusive of TOU-8 customers was $1,813,000. To ensure the sufficient funding for the Award Building Program, we believe that it is reasonable to increase that funding level to $2,500,000, approximately half of Edison's original request. We therefore adopt a budget of $2,500,000 for the Non-Residential New Construction Program. Consistent with our finding in the area of Residential New Construction, we also reject PSD's proposal to limit incentives for heat pumps to facilities located in areas in which natural gas is unavailable.

3. Load Management

Edison's funding request for load management exceeds that recommended by PSD by approximately $6.8 million. This difference is attributable to PSD's proposed reductions in funding of $5.2 million in the Thermal Storage program and $1.6 million in the Water Storage program. The following table illustrates the differences in recommendations between Edison and PSD in this area.

Load Management
Edison/PSD Expenses Comparison
(Thousands of 1985 Dollars)

Description	Edison	PSD	Variance
Load Management			
AC Cycling - Residential	$ 1,846	$1,846	$ 0
Pool Timer	209	209	0
DSS III	1,718	1,718	0
AC Cycling - Non-Residential	109	109	0
Ther. Storage/Off-Peak Cool	6,515	1,359	(5,156)
Interrupt./Curtailable	215	215	0
Water Storage	1,641	0	(1,641)
Total Load Management	12,253	5,456	(6,797)

a. Thermal Energy Storage

The most significant controversy in this proceeding related to DSM centered on funding for Edison's TES program. Testimony was presented by Edison, PSD, CEC, and TESMAC. The CEC and TESMAC support Edison's proposed budget of $6,515,000 for the TES program. PSD recommends total TES funding of $1,359,000, a figure equivalent to 40% (the percentage of non-TOU-8 customer participants) of Edison's 1986 expenditures of $3.4 million. The positions of each of the parties are summarized below followed by our resolution of the issues presented.

(1) Edison

Edison states that its TES program, as currently operated, is a cost-effective energy management program with long-term impacts and one for which Edison has received local and national recognition for its effectiveness and success. Edison further asserts that the program is one which the Commission, under the guidelines established in D.87-05-071, intends the utility to continue to promote.[3] In Edison's opinion, PSD's funding recommendation is inadequate to operate an effective program in 1988 and would devastate the industry.

According to Edison, the benefits of the TES program include the mitigation of uneconomic bypass and the improvement of Edison's minimum load problem. It is Edison's experience that TES offers customers a competitive alternative to self-generation by allowing customers to shift a portion of their cooling load to take

3 Edison cites those portions of D.87-05-071 in which the Commission indicated that utilities should continue to promote reasonable and cost-effective conservation and efficiency options for their large power customers. (D.87-05-071, pp. 4, 9.)

advantage of off-peak rates.[4] Edison further states that PSD has acknowledged that if TES has load retention benefits, the cost-effectiveness results of both Edison and PSD would be understated.

With respect to load retention, Edison has estimated that with the TES option 36 MW of load will be retained on the Edison system in 1988. Without TES as an option, Edison believes that this load would bypass the Edison system and all remaining ratepayers would be financially impacted. If TES is funded as proposed by Edison, Edison states that the anticipated net benefit to nonparticipating customers would be $32 million (net-present value).

Edison strongly disagrees with PSD's assertion that load retention is synonymous with "marketing," for which ratepayer funding would be inappropriate. It is Edison's position that load retention means "keeping a customer who is already an Edison customer on our system." (Tr. at pp. 4763-4764.) By offering TES as an option, Edison believes that it is providing its customers an additional and appropriate means for the customer to manage its energy use wisely and efficiently.

Edison also disputes PSD's decision to base its funding recommendation on 1986 recorded expenditures. Edison states that program activity has significantly escalated over the last 18 months due to increasing customer interest and awareness, coupled with enthusiastic support from the TES industry.

Finally, on the issue of determining the impact of TES, given its load retention attributes, on gas utility customers,

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4 Edison noted that its current Off-Peak Cooling program installation agreement contains a clause which disqualifies customers' eligibility for any incentive payments on systems using any electricity not purchased from Edison for a period of five years. In Edison's view, this clause mitigates the potential for self-generation bypass to occur as a result of a TES incentive from Edison.

Edison maintains that the lack of data on gas utility marginal costs precludes the evaluation of a gas utility customer perspective at this time. Edison states that the favorable RIM results, upon which it relied, are independent of and are not affected by the quantification and inclusion of gas side effects of the TES program.

(2) PSD

PSD states that its funding recommendation is based on 1986 recorded expenditures, the exclusion of TOU-8 customers from participation in TES, and the restriction of program funding to the load shifting, as opposed to load retention, attributes of TES. PSD considers the load retention aspect of TES represents marketing for which ratepayer funding is inappropriate.

PSD acknowledges that TES installations may have a load shifting effect and that for customer's eligible for TOU rate schedules TES could substantially reduce monthly electrical bills. PSD also recognizes that because the initial cost of the system is relatively high, a utility rebate is a valuable incentive to invest in such a system.

PSD states, however, that even assessed as a load shifting program, the TES program demonstrated marginal cost-effectiveness. PSD states that the cost-effectiveness analyses conducted by Edison, PSD, and the CEC for TES showed an all-ratepayer benefit cost ratio ranging from .94 to 1.3. The RIM tests, while over the threshold for funding, were not, in PSD's view, "very robust." PSD believes that these results demonstrate that any major expansion of this program relative to recent authorized levels is unwarranted.

PSD notes that Edison's testimony reflected that by including the load retention benefits of TES, the program's benefit-cost relationships for the RIM test were improved considerably. In contrast to the .53 RIM benefit cost ratio (BCR) of the load shifting portion of TES participants, PSD states that

the load retention portion of TES showed a favorable RIM BCR of 1.34 and the combined program average (load shifting and load retention) RIM BCR became 1.25.

PSD states, however, that the Edison analysis which purports to capture the load retention benefits of TES omits an accounting for the gas-side costs and lost gas revenues. PSD states that Edison has admitted that gas-side impacts should be, but were not at this time, included in the analysis.

In addition to concerns with the cost-effectiveness of the TES program, PSD also asserts that the load retention aspect of this program represents "marketing" for large power customers for which the Commission in D.87-05-071 has prohibited ratepayer funding. In this proceeding, PSD defines marketing programs as those programs which increase the use of at least one fuel (electricity or gas) relative to what would have happened in the absence of the program. According to PSD, the load retention portion of Edison's TES proposal would clearly have the effect of increasing electricity use compared to what would have happened without the TES incentive.

For the TES program, PSD again asserts its position that D.87-05-071 bars ratepayer-funded DSM programs for the large customer class. In developing its proposed funding level for TES, PSD relied on Edison's estimate that 60% of TES funds were allocated to the TOU-8 group. PSD therefore reduced the 1986 recorded TES expenses by this amount.

In the event the Commission were to authorize any funds for either the load retention portion of TES or the participation of large light and power customers, PSD urges that the overall funding level be divided into several categories. These categories would include Load Shifting TES and Electric Load Retention TES with the further breakdown of each of these categories between Medium/Small and Large Customers. PSD proposes that these categories should also be used for any accounting and

reporting requirements. PSD further recommends that customers receiving TES incentives be required to reimburse Edison in the event the customer installs a cogeneration unit in the next five years.

(3) CEC

As stated previously, the CEC supports Edison's funding request for the TES program. The CEC's primary objections to PSD's proposal focus on PSD's definition of the term "marketing."

The CEC believes that PSD has given the term "marketing" a broader definition than the Commission intended in D.87-05-071. It is the CEC's position that "marketing," as used by the Commission in that order, refers to utility programs for which the primary objective or predominant effect is to increase a utility's sales to the exclusion or minimization of conservation efforts. According to the CEC, programs which are designed to make the system more efficient and reduce customer bills should be encouraged even if they may incidentally increase a utility's sales. Those programs which deserve continued funding, in the CEC's opinion, include those designed to shift load, to reduce utility bills, to promote system efficiency, and to defer costly resource additions. The CEC believes that Edison's TES, water storage, and industrial load shaping programs all meet this criteria.

The CEC also agrees with Edison that the TES program is designed both to retain load (i.e., avoid or mitigate uneconomic bypass) and shift load. The CEC states that these dual goals are not aimed at increasing sales and will in fact provide a cheaper and more efficient alternative to the addition by Edison of a new peaking generation resource.

(4) TESMAC

Like the CEC, TESMAC fully supports the funding level proposed by Edison for the TES program. TESMAC believes that

TES provides a cost-effective and important long-term resource for California ratepayers.

TESMAC also agrees with Edison and the CEC that PSD has improperly defined cost-effective load retention as a "marketing activity." TESMAC believes that PSD's overly broad definition of marketing is a formula for the promotion of inefficiency and is inconsistent with D.87-05-071 in which the Commission continued its support for cost-effective conservation and load management programs.

TESMAC also challenges PSD's assertion that Edison's analysis of the load retention benefits of TES should be rejected for its failure to consider any "gas-side" impacts. TESMAC states that it is problematic to quantify "gas-side" impacts when gas marginal costs cannot be adequately determined at this time. Further, TESMAC asserts that PSD's failure to perform such an analysis suggests the substantial methodological and even philosophical problems in currently undertaking such an analysis. TESMAC believes that a program which is cost-effective for the non-participant and all ratepayers would also serve gas consumers who represent those same ratepayers.

In TESMAC's view, TES provides a much more cost-effective and efficient alternative to Edison adding a new peaking generation resource to meet future peak demands. The present $200 per kW TES incentive offered by Edison, in TESMAC's opinion, is much less than the $800 to $1200 per kW cost required for a peaking turbine. In addition, by shifting load to the nighttime, off-peak hours, TESMAC believes that TES may aid any "minimum load" problem being experienced by Edison.

(5) Discussion

Over the past year, we have addressed the issue of funding for TES in several decisions and resolutions. In D.86-12-095, in PG&E's most recent general rate case, we concluded that TES was a cost-effective means of shifting peak load and that

its use was becoming increasingly widespread. In San Diego Gas and Electric Company's (SDG&E) CLMAC proceeding, we determined that the TES program would be funded at $250/kW, but that amounts that could not cost-effectively be used would be returned to ratepayers. We also directed SDG&E to file with the Commission's Evaluation and Compliance (E&C) Division a cost-effectiveness analysis for each funded TES project. (See D.87-08-046.)

The subject of funding for TES has also been recently considered with respect to Edison. In Resolution E-3053, dated September 10, 1987, we were presented with an Edison advice letter requesting the reallocation of $6.4 million of unspent 1985 and 1986 energy management funds. Edison proposed to refund part of the unspent funds and devote the rest to TES and Load Research. PSD protested the advice letter citing the concerns which it has raised in this proceeding. The advice letter was supported, as in this proceeding, by the CEC and Transphase Systems, Inc., a member of TESMAC.

By Resolution E-3053, we concluded that Edison should be authorized to redirect its funds as proposed, but that "the funding limit [for TES] of $200 per kilowatt such as was required for Pacific Gas and Electric Company in Resolution E-3012" would be imposed. (Resolution E-3053, at p. 4.) We also ordered that amounts directed to the TES program which could not be used cost-effectively should be returned to ratepayers. Edison was further directed to undertake the same reporting requirements as had been ordered for SDG&E in D.87-08-046.

In none of these decisions have we determined that any load retention resulting from TES installations is the equivalent of a utility marketing function. Neither do we believe that D.87-05-071, upon which PSD has apparently relied for its definition of marketing, intended this result any more than that decision can be read to exclude TOU-8 customers from participation in any conservation program. With respect to that exclusion, we reject again PSD's assertion and restate our expectation for utilities to retain reasonable and cost-effective conservation and load management programs for large power customers.

Although we believe that a more specific definition of "marketing," which was not included in D.87-05-071, should be developed in the 3-Rs proceeding, we find that certain conclusions about the relation of load retention to marketing can be drawn in this proceeding. To begin with, D.87-05-071 makes clear our continued commitment to reasonable and cost-effective conservation and load management programs even for large power customers and our desire to mitigate uneconomic bypass. The TES program is a DSM program clearly directed to the goal of improving load management for customers installing TES equipment. The fact that the TES program could result in retaining a customer that might, without TES, have chosen to self-generate would also have the desirable impact of preventing bypass. Nowhere in this record is there testimony demonstrating that Edison seeks funding for TES specifically to increase its sales and revenues. Accordingly, we explicitly recognize at this time that load retention is not "marketing" where it serves to allow the utility to keep existing utility loads on the system. We do, however, recognize that there are circumstances where TES could be considered "marketing."

We therefore find that both the load shifting and load retention aspects of TES can be considered in determining the program's cost-effectiveness and that its load retention attributes can be considered in determining the funding for TES. We do not believe that Edison's inability to quantify the gas-side impact of this program is sufficient to discredit the cost-effectiveness ratios achieved by the TES program under Edison's analysis at this time. We do direct Edison, however, to continue to endeavor to quantify this impact consistent with the recently revised Standard Practice Manual for Economic Evaluation of Demand Side Management Programs.

We therefore find that TES is a cost-effective program which should be extended to small, medium, and large power customers. We are concerned, however, that if the load retention aspect of TES continues to be emphasized to the degree represented by Edison (50% of TES program funding) that it will increasingly appear that the program is one designed more to increase load than to manage load. For these reasons, while we find that the TES program is currently cost-effective and both its load shifting and load retention attributes should be funded, the expenditures related to this program should be closely tracked in the coming years. This tracking can take place by continuing the reporting requirements required by Resolution E-3053 and by establishing, for accounting and reporting purposes, the categories of Load Shifting (Medium/Small and Large Customer) and Load Retention (Medium/Small and Large Customer) suggested by PSD.

Although we adopt the position here that cost-effective TES (load retention and load shifting elements) can be funded by ratepayers, we recognize that programs which retain sales in the large light and power (LL&P) class can result in increased profits to Edison if the retained load is not included in sales projections. This is because under the 3-R's decision (D.87-05-071) utility sales to the LL&P class are no longer subject to ERAM. Hence, if the utility's sales are greater than projected, the utility keeps the additional revenues. We do not intend shareholders to profit from ratepayer-funded programs as a result of incomplete sales forecasts. We therefore expect Edison to forecast load that is retained due to its demand-side management programs, and to include that load as part of its sales forecasts in Commission proceedings.

With respect to funding levels, we are concerned that previously authorized levels of $200/kW may not be cost effective. Accordingly, we order Edison to submit a cost-effectiveness analysis for all TES program incentive payments on a project by project basis. Moreover, we direct Edison to quantify the extent to which all TES expenditures are cost-effective in accordance with the recently revised Standard Practice for Economic Evaluation of Demand Management Programs. For overall program funding, we believe that PSD has provided us with the appropriate direction for this funding level in its testimony. Specifically, PSD has stated that its funding recommendation for the TES program, had it included TOU-8 customers, would have been $3.4 million based on recorded 1986 expenditures. Although Edison has indicated an increase in activity, our previous comments reflect our concern that the emphasis in providing incentives for TES installations not shift to a utility marketing effort. For this reason, we adopt and find reasonable a $4 million budget for TES, a funding level which is consistent with recently recorded expenditures and will allow for reasonable growth in the program.

b. Water Storage

The Water Storage Program is another area in which the funding proposals of Edison and PSD significantly differ. Edison requests, and the CEC supports, a budget of $1,641,000 for the Water Storage Program. PSD, on the other hand, recommends that no funds be authorized for this program.

According to PSD, this program would result in energy consumption for water pumping by large agricultural customers and water districts to be shifted to off-peak periods. Because PSD's and Edison's cost-effectiveness results for this program were marginal, the PSD believes that the program should not be funded.

It is Edison's position, to which the CEC has concurred, that this program is designed to enhance Edison's ability to help major agricultural customers to shift load and lower their operating costs. By eliminating funding for this program, Edison states that DSM program incentives will be inequitably distributed among Edison's customer groups. According to Edison, using PSD's proposed funding levels, approximately 56% of all incentives will be distributed to the residential sector, 44% to the commercial/industrial sector, and 0% to the agricultural and water supply customer group.

We concur with Edison that this program should be funded to achieve its legitimate program goals. As we have stated repeatedly in this order, we recognize the need for cost-effective and reasonable conservation and load management programs for large power customers as well as for residential and small commercial customers. Clearly, the agricultural customers should not be left out of this equation especially when their need to control energy costs is as great as any customer class. We therefore adopt and find reasonable Edison's requested funding level of $1,641,000 for the Water Storage Program. Because we had no other record on reasonable funds for this program, however, we ask Edison to undertake whatever reasonable cost-cutting measures are possible to limit any unnecessary and non-cost-effective spending.

4. Residential and Non-residential Marketing

Despite an original funding request for residential and non-residential marketing programs totaling $8.3 million, Edison accepted PSD's recommendation of no funding for these programs. PSD's recommendation, as well as Edison's acceptance of that position, are based on the Commission's determination in D.87-05-071 that ratepayer funds are not to be used for marketing programs. The CEC, however, continues to support the funding of the Industrial Load Shaping Program which is part of non-residential marketing.

Additionally, Edison also urges the Commission in this proceeding, as it has in comments filed in the 3-Rs Rulemaking, to carefully consider the merits of marketing programs in cases where the cost-effectiveness to ratepayers can be demonstrated. Edison also notes its objection to PSD's recommendation that if strategic marketing programs are adopted, customers "give up something" to participate in those programs.

At the present time, we believe that it is appropriate to defer any funding for marketing programs until further analysis of this issue is undertaken in the 3-Rs Rulemaking. As the parties have recognized, D.87-05-071 specifically prohibited ratepayer funding for utility marketing which we find would generally include the type of activities to have been covered in these programs. Edison should therefore pursue the merits of marketing to all customer classes in the 3-R proceeding.

5. <u>Measurement, Evaluation, and Reporting Requirements</u>

In this section, we consider both the funding level of the Measurement and Evaluation Program and the reporting requirements for this program and for DSM generally. With respect to funding, Edison and PSD agree on a level of $7,325,000 for the Measurement and Evaluation Program. These funds cover outside consultant costs associated with technical assessments of new technologies, data collection, and analysis in support of sales and demand forecasts. This funding level reflects Edison's agreement with PSD to transfer $750,000 from FERC Account 923 in the A&G budget to this budget and to transfer an additional $20,000 from A&G expenses to the Customer Survey element of the Commercial Floor Space studies.

Edison, however, does not agree with PSD's recommendation that the expenses associated with the Load Metering and Customer Survey program ($705,000) be included as DSM, as opposed to A&G, expenses. Edison states that it has traditionally categorized these expenses as A&G and that it is appropriate to continue to do so since the primary purpose of these activities is to support Edison's load research efforts. According to Edison, these load research activities are for the most part undertaken to determine marginal cost allocations and rate design.

In addition to the its recommendation to shift funds for load research activities from A&G to DSM, PSD also proposes that Edison's current Measurement and Evaluation and general DSM reporting requirements be changed consistent with D.86-12-095. In that order, the Commission provided a detail listing of reporting requirements and filings.

We find that the overall funding level for this program to which the parties have agreed is reasonable and that PSD's non-budgetary recommendations also have merit. To ensure the proper designation of ratepayer funds, we find that it is reasonable to include the funding for Edison's load research activities as a DSM expense. Edison admitted that while these activities are not necessarily related to DSM, they are in fact useful in that regard. Research on load appears to be appropriately included in an area in which load management is a focus.

To further provide consistency in the review of every utility's DSM programs, we also agree with PSD that the reports required for Edison's DSM programs should be developed using the same guidelines which we recently adopted for PG&E. Those reporting requirements and guidelines are set forth at pages 111 through 118 of D.86-12-095 and are incorporated by reference in this decision. We will direct Edison to follow those guidelines in meeting its reporting requirements and to use the generic DSM definitions being established in the Reporting Requirements Manual drafted in response to D.86-12-095. While Edison has suggested that the restructuring required to meet these new reporting criteria may increase Edison's costs, we find that the overall DSM budget which we have approved in this proceeding should be adequate for Edison to meet any such increased costs.

6. Support Programs

The following table summarizes the recommendations of Edison and PSD in the support programs category. Reductions in funding have been recommended by PSD for each element of this program (Public Awareness, Advertising, and Management/ Administration/Regulatory Support) yielding a total difference between PSD and Edison of $1.3 million.

Support Programs
Edison/PSD Expenses Comparison
(Thousands of 1985 Dollars)

Description Support Programs	Edison	PSD	Variance
Public Awareness	$1,382	$1,031	$ (351)
Advertising	1,000	492	(508)
Mgmt./Admin./Reg. Support	2,402	2,005	(397)
Total Support	4,784	3,528	(1,256)

a. Public Awareness

The $351,000 difference between Edison's request and PSD's recommendation in the Public Awareness area relates primarily to PSD's proposed reduction in the funding requested by Edison for the Save Energy at School program. Edison states that it has requested an increase in funding for this program (67% over 1985 authorized funding) based on two factors. The first, according to Edison, is the expansion of the elementary school program to increase visits from 70 to 250. The second is the development and implementation of a program targeted to the secondary school level. Because PSD did not allow for these changes, Edison believes that PSD's recommended funding level is not sufficient to properly implement the program.

PSD states, however, that while it approves of the Save Energy at School project, it cannot endorse the Edison's proposed 80% increase in funding over recorded 1986 expenses. PSD believes that its recommended 25% increase over 1986 recorded expenditures will allow Edison to begin penetration into secondary schools without significantly increasing funding requirements. For the remaining programs, PSD recommends constraining the test year 1988 funding level to the 1986 recorded level.

We find that PSD has taken into account the activities required by Edison to implement its Save Energy at School program and has proposed a reasonable increase in funding over recorded

1986 expenditures to adequately cover those activities. We also concur with PSD, in our efforts to reasonably constrain conservation and load management expenditures, to hold the remaining programs to funding levels recorded for 1986. We therefore adopt and find reasonable a funding level of $1,031,000 for the Public Awareness program.

b. Advertising

Edison and PSD also vary on the appropriate funding for advertising. PSD has recommended a reduction of Edison's request of $1,000,000 to $492,000.

It is Edison's position that its funding request is necessary to meet its obligation to educate and remind customers of the benefits of energy management. Edison asserts that this role will become increasingly significant in 1988 with the media's continued lack of emphasis on energy issues in general and energy management in particular.

PSD notes, however, that Edison had also asserted an increased need for advertisement in its test year 1985 general rate case. PSD states that in D.84-12-068 at page 202, the Commission rejected Edison's argument, concluding that "general advertising costs should be kept to a minimum especially since many of Edison's programs provide for their own promotion." PSD believes that this finding is still as "current" as the media trends cited by Edison.

We concur with PSD. The fact of individual program promotion has not changed since Edison's last general rate case. We do not believe that it is warranted for Edison to engage in duplicative spending and find that the expenses for general advertising should be minimized. We therefore find reasonable and adopt PSD's proposed budget for Advertising of $492,000.

c. Management/Administration/Regulatory Support

The difference between PSD and Edison for the funding of the Management/Administration/Regulatory Support program is $398,000. PSD states that its recommended funding level of

$2,003,760 for this program is based on historical spending patterns which reflect that administrative and management expenses should not exceed 4.5% of total program costs. In developing its recommendation for support program funding, PSD applied this formula to its own total program costs of $44,528,000.

Edison states that its requested funding level of $2,402,000 for this program is necessary to increase the efficient use of electricity through the development, implementation, and coordination of cost-effective energy management programs. Edison states that it does not agree with PSD's method of funding based on a proportional allocation of administrative and management costs to program costs. Reduced program funding, according to Edison, does not proportionally reduce the effort required to manage and maintain accountability for energy management activities.

Our only problem in adopting the funding level recommended by PSD is that it is based on an overall level of funding which differs from our adopted level. We also seek to ensure adequate funding for Edison to administer and manage its DSM programs. We therefore adopt a funding level of $2,200,000 for Management/Administration/Regulatory Support, a level which we find is more closely matched to our adopted level of funding and which will enable Edison to properly implement its DSM programs.

7. <u>Other Demand Side Management Issues</u>

a. <u>Consolidation of DSM Program Funding</u>

Edison proposes two changes relating to the consolidation of all DSM program funding in base rates starting with Test Year 1988. These changes include (1) the elimination of funding of the Residential Conservation Financing Program (RCFP) through the CLMAC balancing account and (2) the elimination of ERAM funding for the Off-Peak Cooling (TES) program. PSD fully concurs with these recommendations which are also consistent with funding changes made in the PG&E general rate case. (D.86-12-095.)

We concur with the parties and generally adopt these changes as reasonable and consistent with D.86-12-095. To provide an orderly transition to base rate recovery of TES incentive payments, however, all TES incentive payment related to contracts executed prior to January 1, 1988 should continue to be reflected in the ERAM balancing account in accordance with the procedures set forth in D.82-12-055. All TES incentive payments related to contracts executed on and after January 1, 1988, should be reflected in base rates like any other energy management expense. Finally, in implementing the change to base rate recovery of DSM program funding, Edison's CLMAC billing factor should be reduced in an amount consistent with D.87-05-021 in Edison's most recent CLMAC proceeding.

b. <u>$2.5 Million Limit on Funding Shifts</u>

Edison proposes to eliminate the $2.5 million limit on funding shifts within major program categories (i.e., Residential Conservation, Commercial/Industrial/Agricultural Conservation, and Load Management). Edison states that this limit, established in Edison's last general rate case (D.84-12-068), hampers its ability to respond to changing needs. Edison states that it has a demonstrated track record of implementing programs consistent with Commission policy and considers energy management an important resource alternative. Elimination of the funding limit, in Edison's view, will increase Edison's flexibility to derive the maximum benefit from energy management.

PSD, however, strongly recommends that the cap remain in place and that advice letter filings for funding shifts of $2.5 million or more continue to be required. PSD does recommend, however, that the categories be modified to give Edison more flexibility within program areas.

Specifically, PSD recommends that the current three program categories be replaced with the following six categories:

(1) Energy Services and Information Programs (Residential and Non-Residential); (2) Residential and Non-Residential Conservation Incentive Programs; (3) Load Management Programs; (4) Marketing Programs (if any are funded in spite of PSD's recommendations and Edison's withdrawal of those labeled as such); (5) Measurement and Evaluation; and (6) Energy Management Support. PSD further proposes that any funding shift over $2.5 million within categories or any funding shift between the categories should be requested by an advice letter filing. PSD notes that its proposal will provide Edison with more flexibility in managing its conservation and load management program budgets since Edison will not need to submit an advice letter to shift the dollars covered by the cap.

PSD refutes Edison's assertion that PSD did not provide any evidence to support its recommended continuation of the cap on funding shifts. PSD states that the development of its new program categories was based on an independent cost-effectiveness analysis and programmatic review.

We note that the $2.5 million limit on funding shifts at issue in this proceeding has been maintained since Edison's 1983 test year general rate case. (See, D.82-12-055, D.84-12-068.) Specifically, we had intended by our prior orders to grant Edison the discretion to reallocate up to $2.5 million within its three basic conservation program categories. Advice letter filings were required, however, for shifts among the three major program categories or for shifts of greater than $2.5 million within the program category.

Edison now suggests that instead of improving its management flexibility, this funding limit has hampered its ability to respond to Commission conservation directives. We are slightly perplexed by this assertion, unless Edison's proposed elimination of the $2.5 million cap includes the elimination of advice letters for inter-category and intra-category funding shifts. This position is untenable especially with our increased need to control conservation and load management spending.

To enhance Edison's flexibility in managing its DSM program funding, we are at most willing to continue to maintain the $2.5 million allowance on funding shifts within the three major program categories and to reject PSD's suggestion for increasing the number of categories. PSD's suggestion would not seem to improve Edison's flexibility since advice letters would be required for every shift between categories, and the increase in categories would obviously result in an increase in the instances when advice letters would be required. We continue our admonition to Edison stated in D.84-12-068, however, that our E&C Division should be advised of all changes in program emphasis whether or not an advice letter is required. We therefore find reasonable and adopt the continuation of the three basic DSM program categories of Residential Conservation, Commercial/Industrial/Agricultural Conservation, and Load Management, and of advice letter filings for funding shifts between these three major program categories or for shifts of greater than $2.5 million within those categories.

c. Energy Management Salary Budget

As required by Ordering Paragraph 12 of D.84-12-068 in Edison's last general rate case, Edison has reduced the Corporate Energy Management labor budget by over 20% and provided a numerical count by job category and salary range and a description of each job category. Based on these actions, we find that Edison has complied with D.84-12-068.

d. PSD Program Definitions

PSD recommends that for future reporting requirements and applications Edison be directed to use the program definitions established and used by the PSD in this proceeding. According to PSD, its definitions use generic names rather than Edison promotional names (e.g., non-residential new construction rather than Award Building Program), distinguish between participating customer classes, and reflect the program purpose. PSD believes that this approach is essential to tracking similar programs with different names over time and to providing meaningful cost-effectiveness analyses.

We find PSD's suggestion to be meritorious. We believe that as our scrutiny of conservation programs and their cost-effectiveness has intensified so has our need to track these programs and ensure that duplicative spending does not result. In the rate case setting, such consistency is even more critical as multiple programs are reviewed and funding levels are approved. We therefore adopt the generic demand side management definitions being established in the Reporting Requirements Manual and direct Edison to use these definitions in all future rate, offset, and advice letter proceedings.

D. Adopted Results

The following table summarizes our adopted funding levels for Edison's DSM programs:

Adopted 1988 Demand Side Management Program Expenses

Residential Conservation	
Residential Information	$ 1,919
Energy Management Services	4,149
Weather & Retrofit Incentives	768
Energy Eff. Home Builders	1,000
HP Water Heater/Solar Service	40
Appliance Eff. Incentives	4,105
Direct Assistance	5,470
	17,451
Non-Residential Conservation	
Non-Residential Information	767
Energy Management Services	8,029
Energy Management Incentives (Comm.)	3,446
Energy Management Incentives (Ind.)	1,227
Energy Management Incentives (Admin.)	338
New Construction	2,500
	16,307
Load Management	
AC Cycling - Residential	1,846
Pool Timer	209
DSS III	1,718
AC Cycling - Non-Residential	109
Therm. Storage/Off-Peak Cool	4,000
Interrupt./Curtailable	215
Water Storage	1,641
	9,738
Measurement & Evaluation	7,325
Support Programs	
Public Awareness	1,031
Advertising	492
Mgmt./Admin./Reg. Support	2,200
	3,723
Grand Total DSM Programs	54,544
Adjustments for Program Impacts	(350)
Grand Total DSM Programs	54,194

VII. Cogeneration/Small Power Production Programs

A. Edison and PSD Recommendations

Edison has estimated the cost for its Cogeneration and Small Power Development program in 1988 to be $1,765,000. This level of funding, according to Edison, is required to maintain new QF projects already on-line and to ensure their integrated operation with the Edison system.

Edison states that it continues to be committed to the success of reasonable alternative resources as an integral part of its resource plan. According to Edison, by the end of September 1986 it had executed 407 contracts representing 7,277 MW of nameplate capacity. To more efficiently utilize QF generation, Edison states that it is currently negotiating dispatchability provisions with QFs who have executed contracts. The growth in QF generation expected by Edison into the mid-1990's will, in Edison's opinion, reduce the need to commit resources to build base load generating units in the foreseeable future.

The six major components of Edison's Cogeneration and Small Power Development program are execution of contracts, QF project development management, contract administration, regulatory interface, outreach and communication, and special studies. Edison believes these components are necessary to maintain and integrate cogeneration and small power production into the Edison electrical system. According to Edison, the implementation of these program components requires the maintenance of current staffing levels.

PSD states that its review of the Edison cogeneration and small power program indicates that Edison's efforts in signing QF projects and integrating them into the utility electric system have been successful. PSD agrees with Edison's funding request of $1,765,000 for this program, which matches the levels approved in 1985 and 1986.

PSD recommends, however, that for the attrition years, during which currently pending projects will have either become operational or have been abandoned, funding should be reduced by $200,000 in 1989 and $550,000 in 1990. Edison has accepted these adjustments conditioned on the adjustment being subject to a periodic analysis on the optimal funding for the program. PSD accepts this request, with the first such report to be received on August 31, 1988.

We concur with Edison and PSD that the continued effective development of QF resources is an important goal which will permit Edison to meet its resource needs. The funding level for this program requested by Edison and to which PSD has agreed is sufficient to fund the program components. We also agree with PSD that program costs should be tracked to provide for the most cost-effective development of this resource. We therefore find reasonable and adopt the overall program funding of $1,765,000, with reductions of $200,000 in 1989 and $550,000 in 1990 if warranted on the basis of the periodic analysis to be undertaken by PSD and Edison.

VIII. Bypass

On October 1, 1986, the Commission issued Rulemaking (R.) 86-10-001. This rulemaking, also known as the "3-Rs" (risk, return, and ratemaking), was intended to revise electric utility ratemaking mechanisms in response to changing conditions in the electric industry. With the issuance of D.87-05-071 in R.86-10-001, the Commission indicated that its concern with one of these changing conditions, the phenomenon known as "bypass," had become paramount.

As described in D.87-05-071, "bypass" occurs when a customer chooses to generate its own energy rather than accept the service available from the local public utility. Because of lower fossil fuel prices and revitalized generation technology, we recognized in D.87-05-071 that self-generation had become attractive to many customers especially when the utility's rates exceed the cost of self-generation. We further found, however, that this loss of customers from the system could negatively affect remaining customers who would be faced with increased rates due to the utility's fixed costs being borne by a smaller sales base. (D.87-05-071, at pp. 2-3.)

Of particular concern in D.87-05-071 was "uneconomic" bypass, defined in that order as occurring when a customer with self-generation costs exceeding the utility's short-run marginal costs bypasses the utility system. Under these circumstances, we found that the customer's self-generation results in "an inefficient allocation of society's resources." (D.87-05-071, at p. 3.) We also observed that when the customer is able to generate for less than the utility's long-run marginal cost, but more than the utility's short-run marginal cost, the customer should be induced to remain on the system and to postpone construction of its own facility until additional capacity is needed by the utility. (Id.)

We concluded in D.87-05-071 that to address the problems created by bypass certain general solutions suggested themselves. These solutions included: (1) the efficient use of the utility's capacity helping to lower rates by spreading costs over a larger base, (2) the lowering of overall rates by bringing them closer to marginal costs, and (3) the efficient management of the system permitting the utility to act more competitively to retain existing customers and to increase sales when short-run marginal costs are low. (D.87-05-071, at p. 3.)

Guided by these basic principles, we adopted in D.87-05-071 several policies aimed at lessening the detrimental impact of bypass on the utility and its customers. These policies included a commitment to revenue allocation based on Equal Percent of Marginal Cost (EPMC), the elimination of the Attrition Rate Adjustment (ARA) for the large light and power class, the elimination of the Electric Revenue Adjustment Mechanism (ERAM) for the large light and power class, and the use of special contracts between the utilities and the customers in the large light and power class. To implement these policies, further proceedings were ordered to examine guidelines for special contracts, rate options and rate unbundling for different customer classes, and revised forecasts of sales and revenues.

In adopting these policies, however, we indicated that each was subject to the dynamics of changing utility conditions and could be altered in response to those changes. Additionally, we made clear that these policies were not aimed at diminishing our support for alternate generation, but rather to design regulatory mechanisms to promote efficient use of an integrated system of electric resources. (D.87-05-071, at p. 4.)

We believe that the appropriate forum for developing policies governing our response to bypass is clearly R.86-10-001. Those policies, however, play an important and integral role in our findings in this general rate case on issues related to marginal

cost, revenue allocation, rate design, and demand side management programs. This role is reflected in both the parties' positions and our resolution of each of these issues.

Bypass, however, was made a separate issue in this proceeding by Edison's inclusion in its prepared testimony of an exhibit (Exhibit 21) intended to quantify the extent of bypass expected in the future. The study included in Exhibit 21 was later revised and the results of the new study were presented in Exhibit 21-A. Because insufficient time was available for the parties to fully review Exhibit 21-A, this exhibit was not considered to have superseded Exhibit 21, and both exhibits remained in the record in this proceeding.

Based on these exhibits, Edison is forecasting significant amounts of bypass over the next several years.[5] Edison's forecast was developed by examining several non-residential market segments which had been identified by Edison as prospective candidates for uneconomic bypass. These segments included oil refining and processing, process industries (TOU-8), assembly industries (TOU-8), and commercial (TOU-8) and general service (GS-2) customers.

While presenting no forecasts of their own, both PSD and the California Cogeneration Council (CCC) seriously questioned both studies performed by Edison. PSD cited flaws in these studies related to the method of evaluation, the assumptions used, and the information "gaps" which PSD believes "prevents the study from leading to a useful analysis." (PSD Opening Brief, at p. 107.) PSD also states that Edison has acknowledged that the studies did not include an evaluation of the customer's financial ability to

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5 In Exhibit 21-A, Edison indicated a sales reduction for the year 1992, the year on which Edison had focused, of between 9.9 BkWh, based the rate design proposed by Edison in this proceeding, and 14.3 BkWh, based on present rate design.

self-generate or the choice a customer would make, given limited finances, between the cogeneration alternative and other options.

The CCC similarly criticizes Edison's studies and even finds that Edison's definition of "uneconomic" bypass is flawed. Specifically, the CCC charges that Edison has failed to consider the long-term economic perspective in evaluating the benefits of self-generation. In addition to identifying errors in Edison's forecast methodology and assumptions, the CCC also argues that Edison's failure to make available to the CCC its models and data base, which Edison asserts are proprietary, renders Edison's forecasts suspect.

In addition to challenging Edison's studies, both PSD and the CCC offered their own insights into the issue of bypass. PSD concurs with the effort to follow policies like those announced in D.87-05-071. PSD also believes, however, that the ratepayer should not shoulder the responsibility for stemming uneconomic bypass alone. Specifically, PSD states that an additional mechanism for avoiding bypass, in which shareholders and the utility would have an influence and a stake, is the effective and efficient management of the system designed to reduce the utility's revenue requirement. In PSD's opinion, "ever increasing revenue requirements will, if unchecked, make all the allocation and rate design modifications moot as methods to control bypass" and will result in rates which will be "non-competitive on any basis." (PSD Opening Brief, at p. 104.)

The CCC also recognizes that measures should be taken to relieve pressures resulting from uneconomic bypass, including the immediate move to an EPMC revenue allocation for all customers. On the other hand, the CCC warns that other proposals aimed at uneconomic bypass, including Edison's contract rate proposal, should be examined with care to ensure that these "solutions" to short-term concerns do not discourage or sacrifice the long-term benefits of cogeneration and economic bypass.

We applaud Edison's effort to quantify the effects of bypass, but, like PSD and the CCC, have grave reservations regarding the methodology and assumptions used by Edison to make its forecasts. Problems associated with ensuring the certainty of forecasted results are made more acute in dealing with a previously untested area.

We are therefore reluctant to adopt any of the results provided by Edison due to the serious questions raised regarding assumptions and approach and the parties' inability to adequately review the models and data base. Our findings in this decision relating to the use of and access to computer models in developing marginal costs, based in part on Sections 1821, et al., of the California Public Utilities Code, are equally applicable here. In summary of those findings, if the utility chooses to rely on a computer model to support testimony in an evidentiary hearing, the utility must permit access to and verification of the model and related data bases to the extent necessary for cross-examination and rebuttal.

Further, while forecasts of bypass may be helpful in the future to determine the impact of our remedial actions, we do not find that adoption of a particular estimate of bypass is necessary in this proceeding. Our decision in R.86-10-001 makes clear that we are aware of the significance and potential of uneconomic bypass and will follow policies aimed at deterring its spread. This present decision takes into account the findings of D.87-05-071 and implements them in the areas of marginal cost, revenue allocation, rate design, and load management. We believe, however, that any further study or conclusions related to the issue of bypass are appropriately left to R.86-10-001. Due to the absence of sufficient need and analytical support we do not adopt Edison's bypass estimate.

We do wish to assure the CCC and other representatives of alternate generation entities that our goal is in fact to stem the

tide of uneconomic bypass. We will encourage, to the extent that it is required and economically efficient, self-generation based on the use of renewable resources. We believe that the precision with which we have strived to identify Edison's marginal and avoided costs will ensure the receipt of proper price signals by both customers considering bypass of the utility system and those who have already chosen self-generation.

Finally, we note PSD's concern with the effect of "ever increasing revenue requirements" on bypass. As we stated previously, efficiencies in utility management have been recognized in D.87-05-071 as a means of stemming uneconomic bypass. We believe that we have carried out this policy in this proceeding in our careful review of and ultimate findings on Edison's revenue requirements and management programs. It is our hope therefore that our adopted revenue requirement and rate design will prove effective in redressing the negative effects of bypass on Edison and its ratepayers.

IX. Marginal Costs

A. Introduction

With this decision, the Commission continues its commitment to marginal cost ratemaking. Marginal cost is an economic concept which refers to the change in total costs resulting from a change in output. As applied to an electric utility, marginal cost is the change in costs resulting from a change in the number of kilowatts (kW) of capacity and kilowatt-hours (kWh) of energy produced.

Over the past six years, the Commission has used marginal costs to allocate the utility revenue requirement among customer groups and to design the rate levels for individual rate schedules within each customer group. Marginal costs are also used to measure the cost-effectiveness of resource additions, conservation, and load management programs.

Our need to rely on marginal costs for ratemaking has become more acute in recent years as the Commission seeks to ensure the financial integrity of the utility system and in turn the utility's ability to discharge its obligation to provide and maintain adequate and reasonable service. It has been the Commission's long-held view that by using marginal costs in ratesetting each customer will be provided the most accurate price signals regarding his consumption. Not only will this promote conservation and the efficient use of resources, but equity will be achieved by the utility recovering the costs of providing service to each customer in proportion to the costs that customer imposes on the utility system. By providing such cost-related rates, it is additionally our hope that the uneconomic bypass of the utility

system by customers with the capability of self-generation will be averted.[6]

The three principal components of an electric utility's marginal cost are (1) the cost of providing energy, (2) the cost of meeting a customer's demand, and (3) the cost of providing customers with access to the utility system. The first of these components, marginal energy costs, measures the change in total costs caused by a kWh change in energy demand. The second component, marginal demand or capacity costs, measures the change in total costs caused by a kW change in demand. Marginal demand costs are calculated in terms of the incremental investment in physical plant needed to serve the next unit of load and are subdivided into three categories: generation, transmission, and distribution. The third and final component, marginal customer costs, measure the change in total system costs required to hook up a new customer to a utility's distribution system. Ideally, marginal customer costs should reflect the price a subscriber must pay to secure a service connection and to maintain access regardless of area load.

A variation on the theory of marginal costs is the concept of avoided costs. Avoided costs are the costs of producing additional units of energy or capacity which the utility avoids by purchasing power from another source. While marginal costs are the basis for ratesetting, federal statute (the Public Utilities Regulatory Policies Act of 1978 (PURPA)) has dictated that a utility's avoided costs are to be the basis of payments to cogenerators and small power producers (qualifying facilities (QF)) who sell their output to electric utilities. The rules governing these purchases have largely been dictated by the Commission's

6 The subject of bypass is discussed in more detail in a separate part of this order.

consolidated standard offer proceeding, Application (A.) 82-04-044, et al. However, the updating and refinement of the actual prices to be paid QFs takes place in each electric utility's general rate case or Energy Cost Adjustment Clause (ECAC) proceeding.

The similarities between marginal and avoided costs do not end with their conceptual link. Although the Commission is on the eve of finalizing the terms of a long-run standard offer in A.82-04-44, et al., the economic time frame for calculating both marginal and avoided costs within the context of the general rate case remains the "short-run." The "short-run" refers to a situation in which the utility's plant remains constant, but the operation of that plant can be varied. In the "long-run," all aspects of the economic equation can be changed including fixed assets (utility plant) and all variable inputs. In the short-run, the prices paid to qualifying facilities are based on two components--an energy payment based on the utility's cost of producing an additional kWh of energy with the resources that are on the margin and a capacity payment based on the utility's the cost of producing an additional kW of capacity in the short-run.

Previously, the Commission has indicated its intention in calculating marginal and avoided costs of achieving uniformity in the price signals impacting the economic and resource decisions made by utilities, customers, and QFs alike. This goal was realized by the Commission in Southern California Edison Company's (Edison) last general rate case by applying the same short-run methodology for the calculation of both marginal and avoided costs. (Decision (D.) 84-12-068, at p. 230.)

To the extent possible and practicable, a similar effort toward uniformity between marginal and avoided costs will be made in this decision. We recognize, however, that changes to the methodology for pricing qualifying facility power which have been adopted since the last general rate case must be taken into consideration in calculating QF payments.

Our use and calculation of marginal costs over the past six years has been an evolutionary process. Our increasing commitment to and sophistication in developing marginal costs has been matched by the parties. The ultimate result in this decision will hopefully be greater precision in identifying these costs.

During the course of the hearings in this proceeding, a number of parties participated in litigating the issues related to marginal cost and revenue allocation. These parties included Edison, Public Staff Division (PSD), the California Cogeneration Council (CCC), the Cogenerators of Southern California (CSC), the California Manufacturers Association (CMA), the Industrial Users (IU), the California Large Energy Consumers Association and California Steel Producers Group (CLECA/CSPG), the Independent Energy Producers Association (IEP), the Federal Executive Agencies (FEA), the Association of California Water Agencies (ACWA), the California Farm Bureau Federation (Farm Bureau), and Towards Utility Rate Normalization (TURN).

B. Marginal and Avoided Cost Issues

During this proceeding, agreement was reached by Edison and PSD on a number of issues related to costing periods, marginal demand cost, marginal customer cost, and marginal cost revenue responsibility. This agreement was presented in the form of a joint exhibit (Exhibit 41). The following table, based on the joint exhibit, summarizes the areas of agreement between the two parties. No similar exhibit was presented for avoided energy costs or capacity value adjustments used for QF payments.

SUMMARY OF PSD AND EDISON AGREEMENT
MARGINAL COST AND MARGINAL COST REVENUE RESPONSIBILITY

Issue	Agreement
Marginal Generation Cost:	
Methodology	CT Proxy
Total Investment Cost	$614.96/kW
O&M Cost	PSD Escalation
Economic Carrying Charges	10.04% and 10.29%
Marginal Transmission Cost:	
Methodology	Regression Analysis
Total Investment Cost	$263.40/kW
O&M Cost	PSD Escalation
Economic Carrying Charge	10.90%
Marginal Distribution Cost:	
Methodology	Regression Analysis of Non-TSM Investment
Total Investment Cost	$240.00/kW
O&M Cost	PSD Escalation
Economic Carrying Cost	13.08%
Primary Voltage Portion	86.3%
CIAC Adjustment	Included
Marginal Customer Cost:	
Methodology	Typical New Customer, T-S-M Accounts
O&M Allocation	On Capital Investment
O&M Cost	PSD Escalation
Economic Carrying Charge	13.08%
Marginal Energy Cost:	
Variable O&M	0.3¢/kWh
Line Loss Factors	Revised Average Losses
Costing Periods:	
Seasons	Four Month Summer
Summer On-Peak	12:00 n - 6:00 pm
Winter On- and Mid-Peak	Combine Into One Period
Other	Same as Current
Revenue Responsibility Allocation:	
Coincident/Non-Coincident Demand-Classification:	
Generation	100%/0%
Transmission	93%/7%
Primary Distribution	40%/60%
Secondary Distribution	0%/100%
Coincident Demand Allocation	1988 LOLP
Non-Coincident Demand Allocation	Adjusted NC Demand
Franchise Fees & Uncollectible Accts.	Includes FF

The agreement reached by Edison and PSD represents actual agreements on both methodology and results, as well as compromises on such issues as costing periods, marginal customer costs, and marginal cost revenue responsibility. With respect to the latter two areas, Edison and PSD found that the results of their different methodological approaches did not produce significantly different overall results. While PSD and Edison each continue to believe that their own methodologies are superior, agreement to use the results of one of the parties was reached to avoid protracted disputes on issues of minor direct impact on ratepayers. The table reflects that no agreement was reached on the calculation of the incremental energy rate (IER) or the marginal fuel price.

Despite this agreement between Edison and PSD, many parties took issue with both the agreement and even the original positions of Edison and PSD. Because of this circumstance, issues remain even though they were the subject of an agreement between PSD and Edison.

In this proceeding, the issues which were litigated and briefed by the parties related to the following areas: (1) the calculation of marginal and avoided energy costs, including the modeling approach and the assumptions to be used; (2) the calculation of marginal demand and avoided capacity cost; (3) the calculation of marginal distribution and customer costs; and (4) the appropriate costing periods to be used. Each of these areas will be examined with respect to the concepts involved, the specific issues raised, and the parties' positions on those issues.

C. <u>Marginal and Avoided Energy Costs</u>

1. <u>Background</u>

Marginal energy cost is the cost of producing an additional kWh of electricity. Marginal energy costs reflect the change in a utility's total operating costs due to an incremental change in energy demand. Changes in total operating costs include fuel expenses, variable operations and maintenance (O&M) costs, and

purchase power costs. The avoided, as opposed to marginal, energy cost would measure the cost the utility would have incurred to produce an additional kWh but for the presence of the QF.

Both marginal and avoided energy costs vary with the type of plant used to serve a particular load at a specific point in time and the type of fuel used to operate the plant. Marginal and avoided energy costs are therefore calculated using the same basic approach. Specifically, the generating unit which would produce the extra kWh (the marginal unit) is identified. The utility's generating efficiency at the margin is then measured in terms of an IER which is multiplied by the cost of the fuel which would be used to operate the marginal unit (incremental fuel cost). This calculation, which for the test year in a general rate case requires a forecasting of both the IER and the incremental fuel price, yields the marginal or avoided energy cost. Since costs vary according to when the energy is produced, marginal and avoided energy costs are calculated on a time differentiated basis by both time of day and by season.[7]

To provide the necessary forecast of marginal and avoided energy costs, the parties have come to rely increasingly on production cost models. Production cost models simulate the manner in which utility resources meet system loads. This simulation is driven by the resource and load assumptions which are chosen as inputs into the model. These inputs generally operate to produce a least cost result, using available resources (utility plant, QF, or purchased power) in the most economical fashion.

7 Marginal costs are differentiated by time of day between on-peak, mid-peak, and off-peak periods with defined hours, and by season, between summer and winter. The same basic daily and seasonal periods apply to avoided costs. In this proceeding, however, the IEP has proposed that for QF pricing a super off-peak period (1:00 a.m. to 5:00 p.m. daily) be added.

Both Edison and PSD have agreed that the same approach and input assumptions should be used in this proceeding for determining the IER used in both the marginal and avoided energy cost calculations. This position is based in part on the Commission's endorsement of such uniformity in the last Edison general rate case (D.84-12-068, at p. 252.) The methodologies chosen by Edison and PSD permit such a result by being suitable, in their view, for calculating both marginal and avoided energy costs.

Since the last Edison general rate case, however, the Commission has recognized a factor which may be taken into consideration in calculating IERs for QF pricing, but which is not required in calculating the IER used to produce marginal energy costs. (See D.85-07-022.) Specifically, for the long-run standard offer for purchases from QFs, the Commission has determined that the IER should reflect the fact that QFs constitute not just the source for replacing the incremental unit of energy avoided, but also constitute a significant and growing portion of the total resources on which the utility resource plan relies. To capture this occurrence, the Commission has endorsed the use of a "QF In/QF Out" methodology, as opposed to a "QF In" methodology, for the long-run standard offer.

A "QF In" or marginal energy cost simulation essentially assumes that existing QFs (those operating prior to the beginning of the test year) are existing resources, and the IER is developed to include them. The "QF In/QF Out" simulation involves two model runs. As defined by D.85-07-022, the first run determines the total cost of producing power without QFs who will receive the short-run marginal cost price. The second run determines the total cost of producing power with the QFs who receive the short-run marginal cost price. The difference between these two cost runs produces an estimate of the short-run costs that the utility can

avoid by purchasing QF power. (D.85-07-022, at p. 55.)[8] At issue in this proceeding is whether the "QF In/QF Out" methodology can be used to calculate the IER used to develop short-run avoided costs and whether those "QF In/QF Out" methodologies proposed by the parties in this proceeding are consistent with prior Commission orders.

With this background, it is apparent that the two controlling factors in determining a utility's marginal and avoided energy costs are invariably the model or computational approach used and the assumptions made in calculating the IER and incremental fuel cost. It is in fact these subjects which are at issue in this proceeding.

2. Parties Positions

a. Models and Modeling Approaches

While the parties were unanimous in their support for using production cost models to calculate marginal and avoided energy costs, the same unanimity did not apply to identifying which model or associated methodology to use. Certain parties also expressed concerned with respect to their access to the production cost model and the data which Edison used.

For the calculation of both marginal and avoided energy costs, Edison relied on its PROMOD production costing model and the "zero-intercept methodology," a "QF-in" approach. The purpose of the zero intercept methodology is to reflect start-up and no-load

8 The IER is determined by the change in total energy in British thermal units (Btu) in the two simulations divided by the change in total gigawatt-hours (gWh) between the two simulations.

fuel expenses[9] which are costs avoided by QFs, but not included in the calculation of the marginal energy costs directly produced by PROMOD.

PSD performed its marginal and avoided energy cost analysis using the Incremental Analysis Model (IAM) in conjunction with the Production Cost Analysis Model (PCAM). PSD presented both a "QF In/QF Out" and a "QF In" simulation. PSD recommended, however, that the "QF In" approach be used in the general rate case for calculating both marginal and avoided energy costs until a final Commission determination in the consolidated standard offer proceeding (A.82-04-44, et al.) on the propriety of using the "QF In/QF Out" methodology to calculate short-run avoided energy costs. PSD adjusted its marginal and avoided energy costs for start-up and no-load fuel expenses, which are not reflected in the PCAM calculations, by using recorded values derived from an Edison study.

Two interested parties, IEP and CCC, also presented production cost model results. Each chose a model developed by the Environmental Defense Fund called ELFIN. Additionally, both parties included a separate upward adjustment for start-up and no-load fuel expense based on the same recorded Edison values used by PSD. Both parties also proposed the use of a similar "QF In/QF

9 No-load costs are the costs of an incremental addition of load incurred at times other than periods of incremental demand. For example, if dispatching a unit to meet a peak load requires more off-peak generation, the fuel burned in the off-peak hours to make a plant available for on-peak use is really an on-peak expense and thus a no-load cost.

Start-up costs are the costs for fuel burned to bring an incremental unit on line to meet load before the unit generates electricity. While fuel costs attributable to start-ups represent a relatively small portion of total fuel costs, start-ups may be a significant portion of marginal costs.

out" methodology. The position of the CCC was endorsed by another interested party, the CSC.

(1) Edison

It is Edison's position that only its PROMOD model coupled with the use of the zero-intercept methodology, without an adjustment for start-up and no-load fuel expense, produces reasonable IERs and ultimately reasonable marginal and avoided energy costs. According to Edison, the "zero-intercept" methodology, used to capture start-up and no-load fuel expenses, starts with a base case load forecast that is then both increased and decreased for all hours in each mid-peak and on-peak costing period to determine the impact on marginal oil and gas requirements. The "zero-intercept" of a curve representing the changes in marginal oil and gas requirements due to the changes in the load forecast represents the level of marginal heat rates at the base case level of the load in the test year.

In this proceeding, Edison implemented its zero-intercept methodology by making a total of five production cost model runs: a base case run and four runs which reflect the varying of on-peak and mid-peak loads by plus and minus 500 megawatts (MW). Edison believes that its choice of plus and minus 500 MW for the "zero-intercept" methodology produces reasonable results. While Edison can cite no mathematical study to support its position, Edison believes that its use of the 500 MW increment is supported by its considerable experience with production cost modeling. Further, the closeness with which the "zero-intercept" methodology matches the recent historical periods, in Edison's view, substantiates the choice of the 500 MW increment and the methodology itself.

Edison sees several additional benefits in using the "zero-intercept" methodology. Among them, Edison states that only the "zero-intercept" methodology, of those proposed, produces

time-differentiated IERs. Further, Edison notes that the "zero-intercept" methodology was previously adopted in Edison's last general rate case (D.84-12-068).

With respect to the proposals of the other parties, Edison believes that errors in PSD's PCAM modeling exist which are too severe to accept PSD's PCAM results as accurate for future planning or pricing purposes. Specifically, Edison asserts that PCAM modeling of unit dispatch is not correct and that a comparison of PSD's PCAM modeling with that of other parties shows PSD's results to be substantially at variance with the results of other parties' modeling.

Edison's greatest concerns regarding modeling and related methodology are reserved for the proposals made by IEP and the CCC. Specifically, Edison takes issue with the "QF In/QF Out" methodologies proposed by IEP and CCC. Edison argues that (1) the "QF in/QF out" method adopted by the Commission in D.85-07-022 applies to long-run standard offers while IEP and CCC apply the approach to short-run standard offers and (2) the "QF in/QF out" method adopted in D.85-07-022 excludes in one run and includes in the other only future QFs (those QFs expected to sign up for the contract in question during the period being forecast). Edison asserts that IEP and CCC exclude in "QFs out" and include in "QFs in" not only the future QFs, but also existing QFs who already have contracts, a position at odds, in Edison's opinion, with D.85-07-022.

Edison believes that the "fundamental flaw" of the IEP and CCC proposals is that by analyzing "QF In/QF Out" in a static, short-run context, IEP and CCC ignore that short-run standard offer QFs can result in deferring utility resources. In Edison's view using the "QF In/QF Out" methodology to set prices to all existing QFs would result in over-payments due to artificially high IERs, since the utility would have installed its own resources to lower IERs in the absence of these existing QFs.

It is Edison's position that the issue of whether "QF In/QF Out" should be extended to pricing for short-run standard offer QFs is an issue to be resolved in the consolidated standard offer proceeding, A.82-04-44, et al. Until that time, Edison recommends that the zero-intercept methodology continue to be used for short-run marginal cost pricing in the general rate case. Edison disputes the precedential effect of the "QF In/QF Out" methodology being adopted in recent general rate cases. Edison observes that in the San Diego Gas & Electric Company (SDG&E) general rate case, SDG&E had proposed a "QF In/QF Out" methodology. Additionally, Edison states that D.86-12-071, in which the Commission adopted such a methodology for QF pricing for Pacific Gas and Electric Company (PG&E), was specifically intended not to be precedential.[10]

With respect to model and methodological adjustments made by the other parties, Edison is critical of IEP and CCC's external adjustment to the ELFIN production cost runs to account for start-up and no-load costs. Edison notes that most (i.e., 95%) of the adjustment is related to no-load fuel costs. Edison states that such an adjustment of ELFIN results is unnecessary since the ELFIN runs already capture the no-load fuel expense by including as an input the first production block for each oil/gas unit as an average value. Edison states that the average value, as opposed to the incremental value, reflects no-load fuel expenses associated

10 If a "QF In/QF Out" methodology is adopted, Edison states that the Commission may be required to determine the quantity of QF production removed from the "QFs In" scenario in order to develop the "QFs Out" scenario. Edison believes that the CCC erred in its estimate of 76% of QF production receiving short-run standard offer energy prices and removing this amount of QF production. According to Edison, this estimate assumes that all non-standard contracts are variable priced and thereby overstates the amount of variable priced QF production.

with the operation of the unit at its minimum loading level. Edison notes that this level is the same as that at which specific resources are forced to remain on-line as "must-run" units, which is when the no-load fuel expense is incurred. For these reasons, it is Edison's opinion that IEP's and the CCC's separate adjustment for no-load fuel expenses double-counts these expenses.

Edison, however, does not find PSD in error in making an adjustment for no-load and start-up costs for its PCAM analysis since PSD's modeling results reflect an instantaneous marginal energy cost calculation for which such an adjustment is appropriate. Edison objects, however, to PSD's suggestion that the Commission should require further investigation of start-up and no-load fuel expenses in future proceedings since all parties adopted the results of Edison's studies and PSD's problems seemed limited to the need for additional back-up documentation. Edison is willing to provide the information, but does not feel that a mandate to conduct an additional study is warranted.

Finally, Edison responds to concerns regarding the access by other parties to PROMOD and data related to its use. Edison states that it fully complied with the statutory requirements by disclosing data bases, input and output information, and meeting with intervenors to provide them all information "to the extent necessary for cross-examination or rebuttal" (Section 1822(a)). On the subject of the timeliness of data responses, Edison cites the substantial time constraints that face all parties due to the strict schedule to which a general rate case must adhere. Edison believes that given those time constraints, Edison used its best efforts to respond fully and on a timely basis.

(2) PSD

Like Edison, PSD proposes that the Commission use the same methodology to calculate both marginal and avoided energy

costs. PSD similarly cites this Commission's decision endorsing such an approach in Edison's last general rate case (D.84-12-068).

To accomplish this goal, PSD believes that its modeling approach based on the combined use of the PCAM/IAM models was the most accurate forecasting tool presented in the proceeding. This approach involves the use of two separate input files for resources. These two files represent resources which are either "energy limited" (Edison's hydro and certain firm hydro purchases) or "capacity limited" (all steam units, combustion turbines, fossil purchases). Purchases are placed in one or the other files depending on their characteristics.

PSD believes that modeling the characteristics of virtually any resource type, including economy energy, pumped storage, and different hydro types, provides a great deal of flexibility. Units can be dispatched economically, in a predetermined order, or economically with alterations to reflect dispatch limits such as for QFs, "must run" units, and purchased power. PSD states that its model can calculate on-, mid- and off-peak marginal energy costs for up to 20 rate periods and reports IERs and unit data on all modeled resources.

PSD states that its model directly calculates the IERs and marginal costs for all costing periods. Only one adjustment is made external to the model and that is an adjustment to the on-peak incremental energy rate to reflect start-up and no-load fuel. In making its adjustment, PSD utilized a detailed study performed by Edison on the impact of start-up and no-load fuel costs using historic data. PSD believes the use of Edison's study of historic start-up and no-load fuel relationships provides the most accurate means of forecasting those costs.

With respect to the models and approaches used by the other parties, PSD notes that, unlike IAM/PCAM, the PROMOD model used by Edison does not produce a direct calculation of marginal energy costs for all costing periods. Instead, PROMOD is

used directly to compute only off-peak marginal costs with the "zero intercept" methodology being used to calculate on- and mid-peak marginal energy costs.

Additionally, PSD questions and considers arbitrary Edison's use of the plus and minus 500 MW variations of on-peak and mid-peak loads in developing marginal energy costs for those time period. PSD criticizes the lack of scientific basis for the use of this particular increment other than Edison's assertion that the adjustment yields more reasonable results than the adjustment is not made. PSD also notes that the plus and minus 500 MW adjustment in this case differs from Edison's last general rate case in which two alternative adjustments were used--+/- 400 MW and +/- 800 MW.

On the subject of the use of ELFIN by IEP and the CCC, PSD states that it uses ELFIN extensively for resource planning purposes and for the long-run marginal costs used in evaluating the cost-effectiveness of resource additions and demand side management proposals. It is not clear to the PSD, however, that ELFIN is capable of computing marginal energy costs for various time periods. While there are no obvious inherent problems, PSD notes that the ELFIN simulations produced consistently higher incremental energy rates than PSD or Edison without an explanation.

PSD also references ELFIN's potential for double-counting of start-up and no-load fuel. PSD notes in particular IEP's testimony that ELFIN uses average heat rates at the minimum MW level of a unit, thereby accounting for no-load costs. If the average heat rate option is used on ELFIN then an external adjustment of start-up and no-load Btus should not be made to the IER.

With respect to the calculation of avoided energy payments for QF pricing, PSD supports a "QF In" approach. In doing so, PSD points out that the "QF In" approach was the one last used for Edison. In addition, while the Commission appears to have

chosen the results from a "QF In/QF Out" simulation for the most recent PG&E test year, the PSD does not believe that the Commission expressed any commitment to that method. Thus, the PSD recommends that until the Commission makes it clear as to what approach is to be utilized, consistency requires the continued use of the "QF In" method.

Recognizing the possibility of a "QF In/QF Out" approach being adopted in this proceeding, PSD, however, also offered results from using such a methodology. In performing the "QF In/QF Out" simulation, PSD removed 793 MWs of QFs and 4,715 gWh. These numbers were based on information provided by Edison as to the level of QF capacity paid on the basis of variable IERs.

(3) CCC

For this proceeding, the CCC endorses the use of the ELFIN model and a "QF In/QF Out" methodology for calculating avoided energy costs. The CCC notes that this methodology was adopted in the last two general rate cases involving SDG&E (D.85-12-108) and PG&E (D.86-12-091), and its use for QF pricing has been reaffirmed in D.86-07-004. Although the CCC is aware of the Commission's intention to clarify the "QF In/QF Out" methodology in A.82-04-44, et al., the CCC believes that until there is a change in policy, the "QF In/QF Out" methodology should be followed.

In implementing the "QF In/QF Out" methodology, the CCC included all QFs expected to be generating power in the "QF In" case. For the "QF Out" case, all QFs whose pricing is variable are removed, while those QFs with fixed prices are included. The CCC recommends that the Commission characterize 76% of QF contracts as variable priced, based on Edison's responses to data to the CCC and on the assumption that only QFs with Interim Standard Offer 4 contracts have fixed prices.

The CCC believes that it has correctly implemented the "QF In/QF Out" methodology and properly relied on the ELFIN model. The CCC notes that "[a]mong the range of possible choices, ELFIN is the most widely used publicly available production simulation model" and "utilizes a probabilistic dispatch algorithm conceptually identical to that which underlies PROMOD." (Exhibit 102, at p. 4-2 - 4-3.) Further, the CCC states that the ELFIN model has been shown to provide both reliable and accurate simulation results and is used by both the PSD and the California Energy Commission.

The CCC states that it took the initial step in using ELFIN of calibrating or matching the model with PROMOD to ensure that the two models were run with consistent empirical foundations. In the CCC's opinion, the success of its efforts were confirmed by the fact that the CCC's calibrated runs resulted in a deviation below 5% for all categories. After calibration, the CCC then changed Edison's assumptions that, in the CCC's opinion, were flawed, outmoded, or incorrect. The corrected simulations resulted in a marginal energy cost of 25.2 mills/kWh. Based on a gas cost of $2.52/MMBtu, an IER of 9,988 Btu/kWh resulted. This simulation included an adjustment for start-up and no-load costs.

Unlike PROMOD, the CCC confirms that ELFIN does not have a unit commitment capability and does not capture no-load and start-up costs. The CCC states that it compensated for the absence of these features by selecting the most likely marginal units to be "must-run" units and by making an external adjustment for no-load and start-up costs. Specifically, the CCC used time-weighted adders from Edison's historical studies to adjust its IER to capture these costs. The CCC notes that Edison does not dispute the need for a separate adjustment to the ELFIN model to account for start-up expenses.

With respect to the no-load adjustment, the CCC asks that the Commission reject Edison's assertion that this adjustment results in double-counting no-load costs. The CCC agrees with IEP that with ELFIN there may be some potential for double-counting of these costs, but that this double-counting is insignificant. Specifically, the cost effect on the $58,000,000 production cost difference between IEP's "QF In/QF Out" runs was merely $26,000 and had no effect on the ultimate IER result.

The CCC also believes that two other adjustments are required to translate the marginal energy cost and IER estimates into actual QF payments. First, in a manner consistent with the overall valuation of QF production, each of the marginal energy costs and IER estimates should be adjusted for the appropriate level of line losses and variable O&M expenses that would have been incurred by the utility but for the presence of QFs. The CCC agrees to the use of Edison's calculations of these factors. Second, each of the resulting payments should be time-differentiated to the extent that variations in marginal energy costs are expected to be significant across days, weeks, or months of the year.

In response to Edison's proposed methodology, the CCC challenges both the access provided by Edison to PROMOD as well as Edison's modeling approach. The CCC states that because Edison regards PROMOD as propriety, Edison refuses to submit the model for assessment. In turn, the CCC asserts that independent evaluation of the validity of the models has been impossible. The CCC believes that Edison's position prevents a fair evaluation of its approach to calculating marginal costs and is in contravention of Public Utilities Code Section 1822.[11] The CCC believes that when a utility refuses to submit its computer models to independent

11 Section 1822 provides generally that, to the extent necessary for cross-examination or rebuttal, the Commission and interested parties shall have access to any computer model and related data that is the basis for any testimony or exhibit in a Commission proceeding. The requirements of this statute and the status of the Commission rules governing computer access are included in our discussion on marginal energy costs.

verification, the Commission should impose stringent burdens of proof to ensure fair evaluation of all forecasts.

The CCC also criticizes Edison's failure to respond to the data requests of intervenors in a timely manner. This failure, in the CCC's opinion, severely curtailed the ability of intervenors to fully analyze Edison's showing or complete their own presentations.

With respect to Edison's proposed "zero-intercept" methodology, the CCC believes that this methodology is not consistent with the Commission's adoption of the "QF In/QF Out" methodology and has a number of flaws. Among them, the CCC believes that Edison's approach for calculating costs for the off-peak period ignores the effect of QF power on utility "no-load" and "start-up" costs. Second, the CCC asserts that the "zero-intercept" approach illustrates only the consequences of changing loads on utility operating costs. According to the CCC, this determination does not truly measure avoided costs unlike the "QF In/QF Out" methodology which calculates precisely the implications of QF production on a utility's operating costs. The CCC also notes that at the time the Commission adopted the "zero-intercept" methodology in Edison's last general rate case, the "QF In/QF Out" methodology was not before the Commission.

(4) IEP

IEP similarly proposed the use of ELFIN and the "QF In/QF Out" methodology to calculate avoided energy costs for QF payments. IEP's calculations yielded an IER of 10,147 Btu/kWh. According to IEP, the Commission has determined that the "QF In/QF Out" methodology is in keeping with PURPA's requirement that the QF should be paid on the basis of those costs which the utility avoids due to the presence of QFs. It is therefore reasonable to calculate that price without including those QFs who are not in existence, but will be brought on line as a result of that price. (D.85-07-022, Finding of Fact 25.)

In IEP's view, among the short-run energy price methodologies developed to date, only "QF In/QF Out" reflects the change in total system costs caused by the QFs which will receive a price based on the utility's avoided costs. IEP believes that no persuasive reason has been shown in this proceeding not to implement "QF In/QF Out."

With respect to the adjustment for avoided start-up and no-load fuel consumption, IEP notes that Edison has chosen to rely on the interworkings of the PROMOD model to account for this consumption. IEP believes the Commission should reject this position due to Edison's own admission that PROMOD fails to calculate a value commensurate with what recorded data indicates is appropriate. While Edison proposes to include an adjustment of approximately 550 Btu/kWh, the PROMOD generated value, Edison testified that studies of recorded data show empirically that 620 Btu/kWh is the actual level of avoided start-up and no-load fuel consumption.

IEP also believes that Edison argues erroneously that double-counting will occur if the "QF In/QF Out" results from ELFIN are adjusted. IEP states ELFIN does not estimate plant start-ups, as PROMOD attempts to do, and does not have the ability to account for plant fuel consumption at levels below minimum generating levels (i.e., no-load fuel consumption). Since neither of these phenomenon is accounted for in ELFIN, IEP argues that it is entirely appropriate and necessary to make the type of external adjustment to the IER recommended by IEP to account for start-up and no-load fuel costs.

(5) <u>CSC</u>

The CSC expressly adopts the positions and argument articulated by the CCC in this proceeding. Like the CCC, the CSC takes exception to Edison's failure to timely respond to the data requests of the interested parties. Additionally, the CSC endorses the use of the ELFIN model using a "QF In/QF Out" methodology. The

CSC also endorses IEP's and CCC's adjustment to the ELFIN modeling results for start-up and no-load costs of about 620 Btu/kWh.

b. Input Assumptions

In addition to the type of computer model and specific methodology chosen, equally critical to the calculation of the IER are the assumptions which each party used in performing their respective production cost model simulations. In this proceeding, the vast majority of input values was used in common by all parties and was based on Edison data.

Nevertheless, certain critical assumptions were the subject of debate between the parties. The resource assumptions at issue in this proceeding fall into the following basic categories: (1) base load unit production (nuclear and coal units), (2) economy energy availability and purchases, (3) firm power (capacity and energy) purchases, and (4) QF generation. Differences also exist between the parties regarding the assumptions used for the price of natural gas and minimum load conditions. Concern in this proceeding was also expressed regarding the manner in which IERs should be adjusted to reflect the Commission's adopted input assumptions and the need for an annual update of the IER.

(1) Base Load Unit Production Asumptions

For coal units, Edison proposes that an annual long-range capacity of 62% be used. In support of this assumption, Edison cites the adoption by the California Energy Commission of a 63% capacity factor for Edison's coal units in its ER-VI, January, 1987, Report.

For its nuclear units, Edison proposes an annual long-range capacity factor of 65% for Edison's mature nuclear units. Edison believes that its recommended value is based on the most current information regarding the maintenance schedules of such units. Edison also supports its assumption of a full-year operation of its Palo Verde 3 unit based on the reasonable assumption of a considerable amount of pre-release energy generation in January and February of 1988.

The CCC challenges Edison's proposed capacity factors for both its coal and nuclear units. The CCC asserts that in making its forecast of generation from its coal plants, Edison failed to use historical averages, as the CCC believes the Commission requires (see D.86-07-004), and failed to account for major outage factors. The CCC, along with the PSD, base capacity forecast for each plant on actual performance over the past five years, resulting in an average of a 63% capacity factor.

With respect to Edison's forecast of nuclear power generation, the CCC notes that the Commission has determined that forecasts of the performance of thermal units should be based on a rolling historical five-year average for each specific plant. Alternatively, if five years of operating data are not available, the Commission prescribes use of a national average of similar units. (See D.86-07-004, at p. 86.) Since only San Onofre Nuclear Generating Station (SONGS) 1 of Edison's six nuclear units included in Edison's weighted average capacity factor is older than five years, the national average should be used to forecast performance of all of Edison's other plants.

Under these criteria, SONGS 1 would be modeled with its five-year historical capacity factor of 53%. In contrast, Edison proposes to adjust the historical average for SONGS 1 to diminish the effect of the shutdown that occurred during the five-year period, thus proposing a capacity factor of 57%. The CCC calls this approach unacceptable when the point of the historical average is to use the actual performance of a particular unit, whether poor, average or exceptional, to predict performance for the forecast period.

With respect to the remaining units with less than five years of operating data, the CCC testified that the national average performance of units with capacities in excess of 700 MW ranges from 37% to 86%. However, the mean performance of all units averages between 58% and 60%. The CCC recommends that the Commission adopt 59% as the appropriate capacity factor for these units.

The CCC and the CSC also question Edison's proposed capacity factor of 75% for Palo Verde 3 based on an operating date of November, 1987. The CCC points out that evidence in Edison's ECAC reflects that this date has slipped to no earlier than March 1, 1988. The CCC asks that the Commission assume March 1, 1988 for the commercial operating date for the Palo Verde 3 unit.

(2) Economy Energy Purchases

Each of the parties presented different assumptions regarding the amount of economy energy available and expected to be purchased by Edison from both the Pacific Northwest (PNW) and Pacific Southwest (PSW) regions. The differences were primarily due to the use of differing estimation techniques.

It is Edison's position that because Edison alone forecasted economy energy availability based on detailed computer model simulations of the geographical regions, more analytical weight must be afforded to Edison's assumptions. Edison believes that reliance on expert judgment and historical analysis is not a substitute for the type of extensive analysis of the specific regional resources and loads which it undertook. Edison also notes that reliance on estimates proposed in ECAC is misplaced since the ECAC estimate is for the amount of economy energy expected to be purchased, not the total that was assumed available. Edison asserts that availability, and not price, should be the criteria for determining economy energy purchases.

Edison's revised estimate of economy energy available for the PNW for 1988 was 5,072 gWh.[12] Edison's final estimate of PSW economy energy for 1988 was 7,642 gWh (Table 2, Exhibit 109).

PSD, in developing its estimates of PNW and PSW economy energy availability, used, as a base number, the full year recorded figures for Edison receipt of non-firm energy from December 1985 through November 1986. For this time period, the results were 7,509 gWh for the PNW and 3,199 gWh for the PSW. By 1990, PSD is forecasting a decrease on an annual basis to 652 gWh for the PNW region and 735 gWh for the PSW region, a total of 1,387 gWh. These estimates were based on PSD's resource plan "bridging the gap" between the 1986 recorded figures and the 1990 forecast, with an equal percent reduction in each year.

PSD acknowledges that its forecasts for economy energy are dramatically lower than Edison's and the various interested parties. PSD also notes the variation between these estimates and those presented by PSD in Edison's current ECAC proceeding.

PSD states, however, that reasons exist for the differences in these estimates. Specifically, PSD notes that in ECAC PSD uses short-term forecasts that have close relationships with the recorded usage in the immediate past and are intended to be applicable only to the immediate forecast period. The rate case

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12 Edison's original estimate of economy energy purchases from the PNW region was 5,380 gWh. This estimate was revised in Edison's rebuttal testimony (Exhibit 109) to reflect (1) a reduction in the portion of the Wyodak Coal Plant output available for surplus energy production; and (2) the use of more recent forecasts for the Eastern Montana and Wyoming loads. Edison estimated that the effect of these changes in the PNW model would be to reduce Edison's estimate by about 308 gWh of energy availability. Both factors resulting in the total reduction of 308 gWh are attributable to economy energy purchases.

forecasts, by definition, have to be more in tune with average year forecasts being applicable to the test year and attrition year. PSD notes further that Edison's own forecasts differed between this proceeding and ECAC despite Edison's indication that the forecast period results for the two proceedings should be similar.

PSD also believes that its estimates take into account the recent history of PNW transactions with California. This history, in PSD's view, demonstrates that physical capability does not equate to availability.

Finally, PSD asserts that Edison's models for PNW and PSW economy energy are flawed for failing to consider the most critical element necessary in evaluating the availability of the resource--price. While Edison's PROMOD runs include a price computation for non-firm energy of 60% of the average cost of gas, PSD believes that this ratio is too low noting PSD's own assumption of the PNW non-firm price being 85% of the Edison avoided energy price.[13]

IEP, the CSC, and the CCC all challenge Edison's estimates of economy energy purchases. IEP estimates that 5,557 gWh of economy energy purchases will be made from the PNW region for 1988. IEP states that this estimate which is 190 gWh less than Edison has estimated for the ECAC period reflects the price/quantity relationship, which affects economy energy purchase decisions. The expected level of economy energy purchases is affected by Edison's decision to dispatch its system based on the incremental or spot price of gas.

IEP's estimates for the test year are very similar to those made by Edison for the June 1987 through May 1988 ECAC period. IEP recognizes that these periods are not identical, but

13 PSD states that its estimate is consistent with current price behavior under the Bonneville Power Administration (BPA) Intertie Access Policy.

notes, as did PSD, that in this proceeding Edison testified that there was no reason to believe that the expectations of purchases would differ between these overlapping periods.

The CSC also believes that Edison's modeling of PNW energy availability is flawed. The CSC states that both conceptual and mathematical errors in Edison's model have resulted in substantial overstatements of both the availability of PNW energy (by 1,876 gWh) and the actual purchases of PNW energy (by 2,690 gWh). The CSC believes that these errors include (1) Edison having understated the PNW region's load and the Eastern Montana-Wyoming load and overstated resource availability by ignoring resource generation cost and ownership and (2) ignoring the physical capability of the transmission system resulting in purchases exceeding the intertie capability for over 3,300 hours.

The CSC's approach in estimating PNW energy availability was to use instead only the Northwest Regional Forecast which the CSC believes provided a consistent set of forecast assumptions in a single publication. The CCC endorses the CSC's position and results.

With respect to the PSW model and assumptions, the CCC notes that Edison assumed that in 1988 it would purchase 7,642 gWh of non-firm energy from the Inland Southwest at a cost of 22.4 mills/kWh in on-peak periods and 16.4 mills/kWh in the off-peak periods. The CCC finds these projections flawed for two reasons. First, CCC aserts that, as noted by PSD, Edison's out-of-state economy energy projections were as much as 22% higher than recently recorded levels. Second, the CCC states that for its updated ECAC filing, Edison's expected value for Inland Southwest economy energy had fallen to 4,398 gWh, with an average price of only 14 mills/kWh. The CCC notes that the more current ECAC forecast accounts for the historical 1986 recorded prices, the two-tiered GN-5 rate, and operational considerations. The CCC therefore recommends the adoption of Edison's ECAC energy forecast for the Inland Southwest.

(3) Firm Power Purchases

In this proceeding, the issue arose as to whether or not three purchase power contracts were properly considered by Edison to be firm commitments. The three agreements at issue include: (1) the BPA Memorandum of Understanding (MOU), (2) the Pacific Power & Light Company (PP&L) Memorandum of Agreement, and (3) the Portland General Electric Company (PGE) contract.

Edison states that it has consistently held the position that all three of the contracts are committed resources. Since the close of hearings in this proceeding, Edison has advised the Commission that a definitive contract has now been executed between Edison and PP&L and filed with the Federal Energy Regulatory Commission (FERC) on July 1, 1987 in FERC Docket No. ER 87-521-000. Edison requests the Commission to take official notice of this filing.

With respect to the PGE contract, Edison states that the parties seek to exclude this agreement on the basis that purchases under the contract would be too expensive. Edison states that the economics of the contract are not at issue in this proceeding, that the agreement represents a legally binding commitment which Edison has made, and that exclusion of the contract would result in payments to QFs for duplicate capacity which Edison is already committed to purchase.

The BPA contract is, in Edison's view, an extension of the existing contract between the two parties. According to Edison, the contract, which is scheduled for termination in the summer of 1987, has been the subject of negotiations for the last two years. While the original MOU was removed due to the unfavorable economics perceived by Edison, Edison still expects to have a contract in effect by October, 1987. Edison believes that the resources should be considered committed until it is clear that a new similarly advantageous contract cannot be negotiated. In Edison's view, a finding that the arrangement will not continue causes the ratepayers to lose an opportunity to reap the benefits that have and will continue to exist in the PNW region.

In its testimony, PSD indicated its reservations regarding these contracts by excluding from its assumptions of firm purchase power all but the BPA agreement, the certainty of which PSD also questioned. PSD states that these agreements have not received all of the requisite approvals necessary to allow them to go into effect. PSD also believes that urgency in negotiating these agreements has been minimized by the adoption of the Intertie Access Policy by BPA and the presence of excess capacity on the Edison system, a circumstance which is expected to exist well into the next decade. At this time, the PSD believes that the inclusion of any of these agreements in marginal cost calculations should be done with extreme caution.

The CSC also challenged inclusion of the three agreements, but with respect to Edison's calculation of its Energy Reliability Index (ERI) calculation used in developing avoided capacity costs. To ensure consistency in our findings regarding the status of these agreements, we note the CSC's objections here as well.

Specifically, the CSC notes that no definitive agreement, memorandum, arrangement, or contract of any kind exists between Edison and BPA. Further, Edison has admitted to the 259 MW MOU with BPA being "off-the-table." The CSC believes that the PP&L agreement is even less committed since it had not been made available for review at the time of the hearings. Finally, the CSC notes that the PGE contract is still subject to regulatory review by FERC and contains express provisions calling for a recision or reformation of the contract in the event of a material change caused by the regulatory approval process. The CSC also questions the price negotiated under the agreement since it is higher than the BPA MOU.

(4) QF Generation

During hearings in this proceeding, the CCC, IEP, and the CSC all challenged Edison's original forecast of 1988 QF generation. According to the CCC, an artificially high QF forecast produces lower IERs and ultimately results in underpayments to QFs.

The CCC states that Edison's short-term forecasts of expected QF generation demonstrate the uncertainty with this type of forecasting and underscore a pattern of needing to reduce forecasts to account for lower levels of actual QF generation. Specifically, Edison's forecast has ranged from a high of 14,362 gWh in its CFM-VI filing and 14,174 gWh in its 1986 Resource Plan to a low of 7,786 gWh in its April ECAC update. The CCC recommends that the Commission adopt Edison's April 8, 1987 forecast of 12,694 gWh, reflecting a number of QF start-up delays. This updated 1988 estimate is the most current forecast contained in the record and therefore the best estimate provided to the Commission.

IEP has estimated that QFs will produce 9,192 gWh for sale to Edison in 1988, of which 2,420 gWh will be paid for based on floating or variable energy prices. IEP believes these estimates are reasonable and should be adopted for two reasons. First, IEP's analysis was based on information provided by Edison and a review of Edison's initial and updated forecast reports filed in their 1987 ECAC (A.87-02-019). Second, like the CCC, IEP notes the continual updating by Edison reducing its original forecast to match more current, recorded information.

In Edison's rebuttal testimony (Exhibit 109), Edison concurs that subsequent to the development of Edison's PROMOD simulations in the fall of 1986, changes had occurred in the schedules of some of the QF resources that were expected to start operation in 1988. These changes were reflected in the latest Edison ECAC update, but were not included in the Edison's general rate case filing. Edison therefore revised its original estimate of 14,174 gWh of QF generation for 1988 to reflect the more current information by reducing that figure by 1480 gWh. The result was Edison's acceptance of the CCC's estimate of 12,694 gWh.

(5) Price of Natural Gas

The price of natural gas is a particularly critical input assumption. It is the primary fuel used in Edison's own oil/gas generation and is, therefore, the incremental or marginal/avoided fuel. Differences between Edison, PSD, and the interested parties include both the prices assumed for the gas and the manner in which gas prices are modeled.

In determining the price of natural gas, Edison used a fuel cost of $2.94/MMBtu, which is Edison's forecasted weighted average price for gas during the test year. Edison recommends, however, that the Commission adopt the most current average price. Although Edison also forecasted an incremental cost of gas ($2.15/MMBtu), the weighted average was the only price used in its marginal energy cost calculations.

PSD used both a forecasted average price of gas at $2.52/MMBtu and a "commodity" or "dispatch" price, also called the Tier II price, of $1.996/MMBtu or 79% of the average price. It is the PSD view that while in the long term the price of gas will track the price of oil, in the near term, the existing gas competition, combined with the restructuring of the gas industry, is expected to price gas at a discount to oil. Therefore PSD's forecasted price of natural gas is 95% of its forecasted price of Low Sulphur Waxy Residual Oil (LSWR).

The CCC endorses the 1988 gas price forecast presented by PSD of $2.52/MMBtu based on PSD price and dispatch assessments. The CCC, however, challenges the accuracy of the many and varied gas price forecasts which Edison has presented in its general rate case and ECAC applications. The CCC specifically cites four different gas price forecasts which Edison has offered:

An overall gas price of $2.94/MMBtu for the original GRC application, an ECAC forecast of $2.68/MMBtu for the first five months of 1988, a revised ECAC forecast of $2.90/MMBtu, and a $2.70/MMBtu for all of 1988 used in its PROMOD simulation.

Like Edison, IEP used a weighted average gas price in its production cost analysis. PSD points out, however, that the ELFIN model used by IEP does not permit the use of a fuel dispatch price.

Edison takes issue with the use by PSD and the CCC of a Tier II price of gas for the purpose of model dispatch. Since the Commission is now paying QFs using short-run marginal costs of energy that reflect the weighted average price Edison pays for gas rather than the Tier II price, developing IERs based on models which dispatch at the Tier II price of gas would be incorrect. In reply to Edison's challenge to PSD's use of Tier II prices, PSD states that PSD's IAM model has the capability to dispatch units based on the spot price of gas. After fixing the dispatch order, however, PSD notes that the actual weighted average price of gas can then be input into the model for the purpose of marginal cost and IER calculation, a step which PSD took. In PSD's view, this modeling approach in fact most accurately reflects reality since the utility dispatchers never dispatch units based on the average price of gas. PSD further notes that it correctly modeled QF payments on the basis of the average price of gas.

(6) Minimum Load Conditions

Minimum load conditions can be defined as the point where oil and gas fired power plants either have been turned off or are being operated at their minimum level to meet system security needs or operational constraints. During minimum load conditions, low-cost purchased power may be rejected. To the extent that Edison is required by contract to purchase higher cost power during minimum load conditions, a portion of the potential cost savings is not realized.

Edison states that in an attempt to calculate the anticipated minimum load conditions Edison used a simple regression analysis methodology. Edison acknowledges that this approach would not necessarily produce an exactly correct estimate of the minimum load hours. However, the regression did show that the expected minimum load hours would increase over time and probably be at a maximum in the 1989 to 1991 time frame. Since the only major resource additions to the Edison resource plan in the next two to three years are QF resources, the correlation of increasing minimum load conditions due to QF resource additions, as Edison did, is justifiable.

The CCC objects to Edison's methodology for the following reasons: (1) Edison failed to validate its forecasts of rejected economy energy; (2) the assumptions contained in Edison's resource plans are incorrect due to erroneously high forecasts of the availability of economy energy, QF generation, and nuclear and coal generation are too high; (3) the simulations of the Edison system do not accurately reflect the operational flexibility of the system failing to account for several factors that would reduce "must run" constraints; and (4) Edison has provided no proof that its regression equation is valid. According to the CCC, it is unlikely that a simple regression over the years can be meaningful, particularly in light of the fact that the addition of SONGS 2 and 3, the Palo Verde units, and the Intermountain Power Plant Units present highly significant perturbations to the Edison system.

The CCC also refutes Edison's assertion that QFs cause minimum load conditions. Due to additions of a substantial amount of base load capacity to the Edison system in recent years and levels of new coal and nuclear resources, the CCC contends that Edison is precluded from attributing minimum load conditions to any single generation resource.

(7) Miscellaneous Input Assumptions

In its brief Edison expressed concerns about four additional modeling or input differences: (1) heat rate input, (2) load shape data, (3) unit commitment and dispatch, and (4) choice of resource plan. Beginning with heat rate input, Edison expresses concern with respect to the data sets and model manipulation undertaken by IEP and the CCC. Edison also claims that different load shape data was used by Edison and IEP as opposed to the CCC. Edison believes that no significant comparison can be made between the results of two simulation model outputs if the models use different load shapes.

With respect to unit commitment and dispatch, Edison notes that one major difference in the ELFIN simulation modeling and the PROMOD modeling is the treatment of "must run" units. Edison states that the "must run" designation of the coal, nuclear, some hydro, and QF resources is essentially correct. Edison asserts, however, that the "must run" designation of oil and gas units used by both the CCC and IEP is not correct. With reference to historical data, Edison would expect that the production from these units would amount to significantly less than the 72% of all oil/gas energy production projected for test year 1988.

Edison is also troubled by the fact that the CCC, IEP, and PSD simulations of the Edison system were not based on the Edison resource plan. According to Edison, these resource differences may be minor in some circumstances and major in others, but without the use of consistent resource plan assumptions, exclusive of the three contracts under dispute, no valid comparison can be made.

(8) Adjusting IERs to Reflect Commission Adopted Input Assumptions

If the Commission chooses to use input assumptions different than those filed by Edison, Edison believes that the Commission must have some means for adjusting IERs. Edison therefore proposes use of Figure 3 of Exhibit 110 which shows IER sensitivity by plotting a line connecting recorded 1985 and 1986 IERs with Edison's and the CCC's forecasted 1988 IERs as a function of base loaded energy. The slope of this line is about -25 Btus/kWh per 1,000 gWh increase in base loaded energy. Any change in economy energy purchase, base load production from Edison coal and nuclear units, or QF purchases reflected in the input assumptions adopted by the Commission can be converted to the corresponding change in IERs using this linear relationship. Edison believes that the reasonableness of this approach is further enhanced by Edison having demonstrated that the CCC's and the CSC's claims of high sensitivity to changing input assumptions are contrary to the facts.

Additionally, Edison notes that only its and the CCC's (upon removing the start-up and no-load fuel adjustment) results reflect the expected decline in IERs anticipated with increasing "base loaded energy." The IER values produced by IEP, before the start-up, no-load fuel adjustment, and the PSD values are higher than 1986 recorded IERs despite projected increases in base loaded energy.

PSD disputes Edison's assertion that only its "zero-intercept" approach shows a proper trend in forecasted IERs on the basis that an increase is expected in "base loaded energy" production from 1986 to 1988. PSD counters this assertion by stating that even though the production from base loaded units may increase in 1988, economy energy and firm purchase contracts are forecasted to decrease. PSD points out that these decreases will have the effect of increasing the IER.

The CCC believes that despite Edison's concession that certain of the CCC's forecasts were better due to the availability of more recent data, Edison has erred by not rerunning its PROMOD model with the corrected assumptions. The CCC disputes Edison's assertion that IERs are relatively insensitive to changes in input assumptions and those changes can be reflected as proposed above by Edison. The CCC assails Edison's attempt to diminish the importance of using the corrected assumptions as undermining the very purpose of these proceedings--accurate formulation of Edison's marginal energy costs.

The CCC also takes issue with Edison's argument that increases in forecasts of base load energy production intuitively mean other parties are in error in proposing increases in the IER over the 1985 value. The CCC believes that, by taking this position, Edison has ignored the fact that other significant assumptions have drastically changed since the last general rate case and that those assumptions also affect the calculation of the IER.

The CSC, like the CCC, similarly refute the claim by Edison that changes in base load resource generation or purchased power inputs produce little change in the IER. The CSC notes that Edison's opinion, assertedly based on historical analysis, does not withstand scrutiny even when compared to Edison's own production model runs. The CSC asserts even Edison implicitly admitted in its rebuttal testimony that a sensitivity analysis using a production simulation model is the appropriate method for calculating IERs. The CSC concludes that since no such sensitivities were presented in the record, the Commission must decide the appropriate IER level based on the Edison, PSD, IEP, CCC, or CSC recommendations.

(9) <u>Annual IER Update</u>

The CCC proposes that the Commission institute an annual updating procedure for the IER in order to minimize the risks associated with forecasting. For ease of implementation, the load and resource assumptions adopted in the annual ECAC proceeding could be used as the basis for the update. The utilities would then file an application proposing avoided energy payments to QFs based on the approved assumptions. The CCC recommends that the Commission adopt an annual IER in this proceeding and defer to

A.82-04-44, et al., issues related to updating. The CCC notes that the same approach was used in D.86-12-091 in PG&E's last general rate case.

c. Miscellaneous Avoided Cost Issues Raised by Edison

Edison also proposed to change some of the factors which enter into the calculation of avoided energy costs. These changes are as follows:

-- Variable O&M expenses adder: $0.003/kWh

-- Oil-gas efficiency conversion factor: 1.05

-- Sub-transmission energy line loss factor: 1.023

-- Primary level energy line loss factor: 1.026

Edison asserts that no party to this proceeding has raised issue with these modifications. Edison therefore recommends their adoption.

d. Proposed IER Results

The following table summarizes the results of each party's IER analysis:

Summary of IERs

Party	"QF In" Run (Btu/kWh)	"QF In/QF Out" Run (Btu/kWh) Proposed	Unadjusted ELFIN Results [14]
Edison	9,251		
PSD	9,626	9,775	
IEP		10,147	9,511
CCC		9,988	9,369

14 These are the results achieved by the CCC and IEP using the ELFIN model and their respective "QF In/QF Out" methodologies prior to the external adjustment for start-up and no-load costs.

3. Discussion

a. Computer Model and Input Assumption Access and Use

We are disheartened to be confronted in this case with basic issues related to the litigation of marginal costs which we felt had been resolved. Primary among these is the access by the parties to computer models and related data supporting testimony and recommendations in this case. In Edison's last general rate case, D.84-12-068, we had endorsed PSD's suggestion of an OII into the subject of a uniform computer model. We felt that such uniformity would end suspicion and enhance understanding of computer models. As suggested by PSD, we also directed Edison "in its next general rate case to provide related computer data upon the filing of its application" to avoid the data gathering problems PSD had experienced in that proceeding. (D.84-12-068, at p. 256.)

Since the issuance of D.84-12-068, the Legislature has also been active in the area of computer model access. Specifically, in September, 1985, the Legislature directed the Commission to embark on a major program to assess and validate utility computer models and to improve public understanding and access to such models. Assembly Bill 475 was enacted at that time adding Section 585 and Sections 1821 through 1824 to the California Public Utilities Code. These code sections provide, among other things, that any computer model and related data base that is the basis for any testimony or exhibit shall be available to the Commission and parties to hearings to the extent necessary for cross-examination and rebuttal. The Commission is further required to adopt rules to govern access and verification of the computer models. These rules are to include procedural safeguards that protect data bases and models not owned by the public utilities.

Pursuant to AB 475, the Commission undertook and completed its first report to the Legislature on December 31, 1986. This report focused on reviewing and explaining the electric utility production cost models. Reserved to this year's (1987) study is the adoption of rules governing access to utility models.

Despite this effort, we find that little progress toward uniformity in production cost models or availability of related data has been made within the context of the general rate case. Instead of a uniform model used by all parties, we were presented with a total of three models, the efficacy of each of which was the subject of debate. Further, in spite of our admonitions to Edison in their last general rate case regarding the early provision of data related to the use of its computer model, interested parties were still without such data as hearings on the issue of marginal cost commenced.

The difficulty of assessing the validity of various computer models is made more acute in the setting of a general rate case. With a myriad of issues to hear and decide and a strict timetable with which to adhere, the Commission is ill-equipped to decide issues related to the verification of complex computer models during a general rate case. We find that this situation will only worsen should the possibility of an annual update of the IER in ECAC proceedings be realized. The ECAC proceeding, even more than the general rate case, is already burdened by significant time and staffing limitations.[15]

In this case, we note that the results produced by the computer models used in this proceeding were remarkably similar. However, it is not our job to guess why this result occurred, but to know. Among the reasons which suggest themselves are (1) coincidence, (2) negligible impact of utilizing either PROMOD,

15 We note that our belief regarding the possibility of an annual update of the IER will lead us to adopt an annual IER in this proceeding, as suggested by the CCC. However, whether or not this situation will actually occur is appropriately to be decided in A.82-04-44, et al.

ELFIN, or IAM/PCAM in calculating Edison's IER, (3) negligible impact of differing input assumptions, or (4) negligible impact of differing methodologies.

It is our concern that even if all of these circumstances were true in this particular rate case, such circumstances could be non-repeating. That is, the sum total of the model, methodology, or assumption differences did not alter the IER significantly in this case, but the sum or even one of these factors in another case could yield highly dissimilar results. In attempting to forecast the future, an already speculative science, the Commission does not want to leave to chance the understanding of the tools upon which we rely to provide the adopted forecast.

For these reasons, we find that in Edison's, as well as PG&E's and SDG&E's, future general rate cases, ECAC proceedings, or other proceedings designated by A.82-04-44, et al. for developing marginal or avoided energy costs, all parties presenting testimony requiring the use of a production simulation model must provide a "base case" run using the same model. Each party will, of course, also have the opportunity to present testimony using its model of choice and explain its preferences for that model. However, the requirement that the same model must be used to present a base case will aid the Commission, as a starting point, in determining whether model, assumption, or methodological differences are causing the different results. The need for such an approach may lessen over time as ours and the parties' sophistication regarding computer models increases. Additionally, work related to the implementation of AB 475 will ultimately determine the manner in which models are to be used and accessed.

To achieve our goal, we find that the model which lends itself best to our purpose is ELFIN. As has been shown in this proceeding, ELFIN is the most accessible production simulation computer model in use at the present time and has been employed for the greatest number of uses.

We note certain parties' concerns regarding the efficacy of using ELFIN for short-run marginal cost results. We believe that this shortcoming, if one exists, can be addressed by each party either suggesting a means of adjusting the model to overcome any problem or citing the deficiency as a basis for reliance on an alternate model or approach. We discuss below the propriety of adjusting the ELFIN model to reflect start-up and no-load costs.

In any event, ELFIN results will be produced by all parties and can be compared by the Commission between each party and between other model results. We remind the parties that our goal is not to endorse or reflect a preference ELFIN over all other models, but rather to provide a common basis for the Commission to evaluate the parties' showings and to determine the proper forecasted result within the limited time frames provided by general rate case and ECAC proceedings.

Similarly, we are concerned with continued problems related to access to input assumptions. The CCC correctly notes that issues relating to updating IERs will be ultimately decided in A.82-04-44, et al. We note, however, their comment that implementation of this annual update can be "eased" by load and resource assumptions adopted in the annual ECAC proceeding being used as the basis for the update. What this suggestion overlooks is the process by which those assumptions were adopted--namely, through complex litigation in the ECAC. Therefore, we also believe it is necessary to provide direction in this decision to streamline that process as well. Similar to our findings on the ELFIN base case run, it is our intention that procedures similar to those adopted below for Edison's ECAC will be followed by PG&E and SDG&E in their ECAC filings and by all three utilities in their general rate case filings or any filings designated by A.82-04-44 for the development of avoided or marginal energy costs.

Specifically, we direct PSD for Edison's next ECAC or forum designated in A.82-04-44, et al. for the development of IERs, to hold a workshop no later than one week following Edison's ECAC filing. The purpose of this workshop will be to determine the data sets, resource plans, load shape, heat rate input, unit commitment and dispatch, minimum load conditions, resource assumptions, marginal fuel assumptions, and all other pertinent data which Edison used to calculate its IER. We have included in our list the very items with which Edison took issue in this case and claimed prevented comparisons between the results of the various parties.

The purpose of this workshop will not only be to obtain data which Edison used in its calculation, but to also provide a forum in which the parties can agree, to the extent possible, on the assumptions to be used and the appropriate source of those assumptions. The Director of the Commission's Advisory and Compliance Division shall appoint an aribiter for the workshop to resolve any issues related to the development of a common data set upon which agreement cannot be reached by the parties. Sufficient time will be available following the workshop for PSD and interested parties to prepare their ECAC reports and testimony.

b. Adopted Results

In this case, we have carefully reviewed the record and concluded that the IER to be used for both marginal and avoided energy costs should not result from the averaging of the parties' proposals, an alternative suggested by the outcome in D.86-08-083 (PG&E). The reasons for this approach are several. First, we believe that much of the uncertainty regarding the appropriate methodology for calculating marginal and avoided energy costs will be removed this year. Second, should the IER, as we believe it will, be updated on an annual basis, we find it critical to examine the input assumptions which were used in this case and will no doubt be in issue again in any update.

Specifically, we have concluded that the Commission has endorsed the calculation of two IERs--one for marginal energy cost determinations and one for avoided energy cost determinations.

This split is appropriate since the avoided energy cost is to be used to pay QFs and should in turn reflect the contribution made by the QF in avoiding utility energy costs. While the ultimate methodology used to calculate this difference will be developed and approved in A.82-04-44, et al., we find that the Commission has continued to move in the direction of applying the "QF In/QF Out" methodology for short-run, as well as for long-run, avoided energy cost calculations. (See D.85-12-108, D.86-07-004, D.86-12-091.)

As correctly stated by both the CCC and the CSC, our reliance on PROMOD and the "zero-intercept" methodology in Edison's last general rate case was primarily a default position. In particular, the "QF In/QF Out" methodology had not been adopted and the models and related methodologies available to us that proceeding were limited. This case provides a completely different scenario with several different models, methodologies, and assumptions having been presented.

We recognize that our conclusion to use different IERs for ratemaking and QF pricing represents a departure for our policy announced in Edison's last general rate case. In that proceeding, as noted by PSD and Edison, we endorsed uniformity in marginal and avoided cost results for all purposes for which these costs are used. Although practically this approach greatly simplifies our task of determining these costs, we do not believe that it allows us to meet our obligation to provide the most accurate prices to QFs based on avoided costs and, at the same time, to provide the most accurate price signals to consumers regarding their electric consumption.

Unfortunately, only one party to this proceeding presented IER results based on a "QF In" (marginal cost) approach and a "QF In/QF Out" (avoided cost) approach--PSD. Fortunately, the results produced by PSD were the least controverted in this proceeding, provided the "correct trend" which would be expected from using these two approaches (a slightly higher IER using the

"QF In/ QF Out" approach), were within the range of IERs proposed by the other parties, and were derived from the same models. The models and methodologies employed by PSD also appeared to present the least concern to the other parties.

In contrast, much debate centered on the propriety of the "QF In/QF Out" methodologies proposed by the CCC and IEP. We note, as we have previously, that the decision on the appropriate methodology to be applied to a "QF In/QF Out" scenario is to be reached in A.82-04-44, et al. Due to this circumstance, we will not determine whether or not the CCC and IEP properly included "existing" QFs in their implementation of this methodology.

Because ELFIN will be used to provide the "base case" IER calculations in ECAC, however, we do feel it is appropriate to examine the issue of whether the CCC's and IEP's results include a "double-counting" of start-up and no-load costs. In this regard, we believe that the record appears to support PSD's and Edison's position that some "double-counting" does result when the ELFIN model output is externally adjusted to reflect start-up and no-load costs. This effect was in fact acknowledged by IEP, but was dismissed on the grounds that such "double-counting" had an insignificant impact on overall results.

As we move to a period of potential reliance on ELFIN and the "QF In/QF Out" methodology to calculate IERs for QF pricing, the fact of "double-counting" of start-up and no-load costs in using ELFIN, whether insignificant or not in this particular case, could become critical in the future. We therefore find that the CCC and IEP failed properly to take into account the potential for double-counting and to reduce their adjustment of their proposed IERs by the amount of the double-counting.

For the reasons stated above, we find that the resulting IERs proposed by PSD--9,626 Btu/kWh to be used for the marginal energy cost calculation and 9,775 Btu/kWh to be used for the avoided energy cost calculation--are reasonable and should be adopted as annual values in this proceeding. An annual IER is appropriate for adoption in this proceeding due to the likelihood of the IER being the subject of an annual update. The determination of the forum and timing for updating the IER, however, remain reserved for A.82-04-44, et al. Our adopted IER value should therefore remain in effect until updated as prescribed in A.82-04-44 et al.

Our conclusion to adopt the PSD's estimates, however, should not be interpreted as approval of PSD's "QF In/QF Out" methodology, a methodology being considered with other proposals in A.82-04-44, et al. in which proceeding the "QF In/QF Out" issue will be resolved. Neither do we intend by this result to indicate adoption of all of PSD's assumptions or acceptance of Edison's position that changes in such input assumptions have little impact on the calculation of the IER.

Instead, we find that, in this particular case, PSD's numbers are most in keeping with our decision to rely on both a "QF In" approach and a "QF In/QF Out" approach, that PSD's results are clearly within a range of reasonableness based on the totality of the evidence in this proceeding, and that both IER results emanate from the same source (i.e., same model, modeling, and assumptions).

We also do not intend for our adoption of the PSD results to indicate any acquiesence to Edison's position regarding the insensitivity of the IER calculation. The sole support for this contention is apparently the closeness of the parties' recommendations. As stated previously, however, we cannot be sure if this result in this particular case will repeatedly occur. The sensitivity runs necessary to firmly decide this issue, as even Edison recognizes, are not a part of this record.

Considering the likelihood of the IER being updated on an annual basis, however, we do believe that our resolution of the assumptions at issue here will provide useful insight into the proper determination of similar assumptions in the future. In all cases, we believe that the guiding principle in evaluating input assumptions is that the best assumptions embody the most up-to-date, verifiable information.

Base Load Unit Production Assumptions. The CCC has provided the Commission with the most reasonable assumptions regarding Edison's base load unit (coal and nuclear) production. The CCC relied upon the correct standard for evaluating Edison's nuclear power plants with less than five years of operating data--the national average of similar units. For those units, 59% is the appropriate capacity factor. Based on more recent information than was used by Edison, we also adopt the CCC's assumption of a March 1, 1988, commercial operating date for the Palo Verde 3 unit. The CCC and PSD also correctly assumed an average of a 63% capacity factor for Edison's coal plants based on historical averages and consideration of major outage factors.

Economy Energy Purchases. It is in this area that we found PSD's presentation to be the weakest. We found insufficient support for PSD's dramatically different economy energy assumptions and are unpersuaded by PSD's reasoning for making those assumptions. This single problem area in PSD's showing, however, is not sufficient to alter our adoption of PSD's final overall IER results. We find instead that based on the most recently available data that Edison's estimate of 5072 gWh of PNW economy energy purchases and the CCC's estimate (based on Edison's ECAC testimony) of 4,398 gWh of PSW economy energy are reasonable.

Firm Power Purchases. The question of what is a "firm" power purchase arises not only in the context of calculating Edison's IER, but also in the context of calculating Edison's ERI used to determine avoided capacity costs. This latter calculation will be discussed in the following section; however, our

determinations regarding Edison's "firm" power purchases in this section are equally applicable to our discussion of the ERI.[16]

We note the concerns of PSD, the CCC, the CSC, and Edison with respect to this issue. In evaluating these agreements in terms of their inclusion as firm resource assumptions used in calculating an IER, however, it is our job to determine Edison's commitment to purchase the power, rather than to adjudge the economic benefits of the agreement. In assessing whether Edison is truly obligated in a purchase, we do need to examine the totality of circumstances surrounding that contract--its status as to the two parties, its status as to the necessary governmental approval, and last, and perhaps least important in this regard, its acceptability as to price.

We find using this criteria that the BPA MOU cannot be considered a firm contract under any circumstances. Currently, the parties have reached no agreement, and Edison has acknowledged the economic impropriety of its entering the contract as first proposed. We also note PSD's concern regarding the current lack of urgency with respect to Edison signing such an agreement.

With respect to the PP&L and PGE contracts, while both contracts still require governmental review and certain price questions have been raised, we note that the parties have reached agreement and that those agreements have been tendered to the FERC. We find that this course of action indicates Edison's intent to

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16 The only basis for a differing approach in evaluating the efficacy of firm purchase assumptions for calculating IERs and ERIs is that the ERI may be in effect for a longer period of time than the IER. As stated previously, only an annual IER value will be adopted in this proceeding. The period of time in which the ERI will be in effect is an issue to be resolved in A.82-04-44, et al. Currently, that period could be as long as the time between general rate cases (three years). We do not believe, however, that our conclusions would be significantly different given a longer effective period for the ERI.

pursue and honor these agreements and as such both contracts should be considered firm purchases.

QF Generation. We adopt the most recent forecast of QF generation recommended by the CCC and agreed to by Edison of 12,694 gWh.

Minimum Load Conditions. We share the CCC's concerns regarding Edison's forecast of substantial increases in minimum load conditions, Edison's reliance on a regression analysis, and Edison's attribution of minimum load conditions to any single generation resource (i.e., QFs) in the face of increases in other base load resources as well. We believe that future forecasts should provide more specific and verifiable results regarding the causes and effect of minimum load conditions.

Natural Gas Price. We find reasonable and accurate PSD's forecasted average price of gas of $2.52/MMBtu. Unlike Edison, however, we have no difficulty with PSD's use of the "dispatch" or Tier II price as an input to the IAM model in order to most accurately reflect unit dispatch. As pointed out by the CCC, the varied gas price forecasts offered by Edison offered no clear choice regarding the correct forecasted figure.

We conclude this section on marginal and avoided energy costs by adopting those portions of PSD's and Edison's Joint Exhibit 41 on those marginal energy cost issues on which these two parties agreed and which our preceding findings do not impact. We also find reasonable Edison's request to adopt its undisputed changes to the following factors which enter into the calculation of avoided energy costs--variable O&M expenses adder, oil-gas efficiency conversion factor, sub-transmission energy line loss factor, and primary level energy line loss factor.

D. Marginal Demand and Avoided Capacity Costs

1. Background

The marginal cost of demand measures the change in total costs caused by a change in demand. These costs are calculated in terms of the incremental investment in physical plant needed to serve the next unit of load, and therefore relate principally to plant associated with generating and transporting the electricity necessary to satisfy the marginal demand. Components of marginal demand costs are the marginal costs of generation, transmission, and distribution. Because of the relation between marginal distribution and marginal customer costs, the distribution component of marginal demand costs will be considered in our subsequent section on marginal customer costs.

In past general rate cases, the marginal demand costs of generation have been based on the utility's shortage costs. There has been general agreement that a suitable proxy for those costs is the annualized value of a combustion turbine.

Related to generation marginal demand costs are avoided capacity costs. Under a short-run standard offer, the payment made to QFs for capacity are based on the utility's avoided capacity cost which, like the marginal demand cost, is based on the utility's shortage costs. The annualized value of a combustion turbine is similarly used as a proxy for those costs. Because transmission and distribution costs are not avoided by utility purchases of QF power, such costs are not included in payments to QFs. Avoided capacity costs are also used in evaluating resource alternatives and demand side management programs.

While the unadjusted value of a combustion turbine has continued to serve as the basis for determining marginal demand costs, the same has not been true for the calculation of avoided capacity costs used as the basis for payments to QFs. Since Edison's last general rate case, in which such an unadjusted value

was adopted for QF pricing, the Commission has determined that an adjustment of the combustion turbine value is necessary to reflect system reliability. Such an adjustment is generically referred to as a capacity value multiplier.

Specifically, in D.86-07-004 (A.82-04-44, et al.), the Commission noted the general agreement among the parties that a utility's shortage cost payments may be less than the annualized fixed cost of a combustion turbine depending on whether the utility's generation reserves exceed an appropriate reliability criterion. In the subsequently issued D.86-11-071, we reviewed proposals submitted by Edison, PG&E, and SDG&E for capacity value multipliers designed to reflect the system reliability of the three utilities. In that decision we indicated our intention to use, when its development was complete, an ERI based on an Expected Unserved Energy (EUE) target as the basis for adjusting the value of the combustion turbine.

The EUE is a measure of the likely quantity of unmet demand in a given timespan. The ERI is a formula that uses the EUE target of a utility to determine the value of additional capacity to that utility. An ERI based on an EUE target is therefore a means of expressing whether the value of the additional capacity on an electric utility system in a given year is the same as, greater than, or less than, the utility's marginal capacity investment, assumed to be a combustion turbine.

In D.86-11-071 we concluded that system operability, with one historical year as reference point, should be the basis at this time for developing an EUE target. If the projection of EUE for that year is less than the EUE target, then the capacity value will be less than the annualized cost of a combustion turbine. If the projection exceeds the EUE target, and if the year in question is not far enough in the future to allow the utility to build new capacity, then the capacity value of new QFs in that year will exceed such annualized cost. (D.86-11-071, at p. 9.)

In D.86-11-071, while finding that all of the utilities had presented thoughtful proposals, each utility, including Edison, was directed to revise and provide further explanation of their proposals in the June and July, 1987 hearings in A.82-04-44, et al. The Commission, however, accepted in principle Edison's proposal to implement its EUE target in conjunction with a target reserve margin. This approval, however, was conditioned on Edison's valuing capacity for the selected year on whichever target resulted in a lower total EUE for that time period.

In PG&E's most recent general rate case, the Commission recognized the ongoing study of capacity value multipliers taking place in A.82-04-44, et al. The Commission concluded that in the interim the ERI methodology adopted in PG&E's last general rate case (D.83-12-068) would be used to determine the ERI adjustment factor adopted in D.86-12-091.

In an Administrative Law Judge's (ALJ) Ruling issued in this proceeding on March 4, 1987, the ALJ acknowledged that the methodology for calculating adjustments to avoided capacity costs is an issue in A.82-04-44, et al. The ALJ further stated, however, that the general rate case remained the forum for the adoption of the precise values which would be used to determine those costs. Because no capacity value multiplier had been adopted in Edison's last general rate case, as it had been for PG&E, the parties were directed to utilize an ERI adjustment, despite its on-going study in A.82-04-44, et al., in calculating Edison's avoided capacity costs. In the absence of a reasonable EUE target at the time of hearings in this proceeding, the parties were asked to present a "default position, e.g., the target reserve margin," for the Commission's consideration.

2. Parties Positions

a. Marginal Demand Costs

(1) Edison and PSD

Both Edison and PSD agree on the methodology and assumptions for calculating marginal demand costs of generation and transmission. Edison and PSD have used the cost of a combustion turbine as a proxy for calculating generation marginal demand cost and a regression analysis of transmission investment costs versus peak load increases for calculating transmission marginal demand costs.

In order to complete the calculation of the 1988 O&M expenses, one of the components of the marginal demand cost, O&M escalation rates were needed. PSD's O&M escalation rates differed slightly from Edison's, but Edison agreed to accept PSD's rates. The jointly proposed numbers of generation and transmission marginal demand costs are \$69.36/kW and \$33.12/kW, respectively, as shown in Tables 2 and 3 of Exhibit 41. Edison and PSD believe these numbers to be reasonable and urge their adoption by the Commission.

(2) CMA

CMA proposes that generation marginal demand costs, like avoided capacity costs should also reflect an ERI. CMA states that Edison currently has excess generating capacity so that PSD and Edison both show Edison's ERI is substantially lower than the 1.0 which it would be if an appropriate balance of loads and resources existed. CMA believes that failure to recognize the existence of excess capacity in determining the marginal demand cost of generation means that rates based on that cost will incorrectly signal the customers that the excess capacity does not exist.

CMA also states that its testimony demonstrated that the recognition of the ERI in marginal generation costs makes little difference in the revenue allocation to classes. However,

use of the ERI would have significant impact on rate design. CMA asserts that with generation marginal demand costs varying significantly, the appropriate allocation of Large Power revenue requirement within that class would be affected substantially. Specifically, different proportions of the class revenue requirement would be allocated to the on-peak demand portion of scheduled rates.

b. Avoided Capacity Costs

(1) Edison

It is Edison's position that it has properly implemented the Commission's D.86-07-004 and D.86-11-071 by proposing an ERI using target EUE as a basis to project the target reserve margins for future years. Edison states that its results, which stem from detailed computer modeling and the development of a mathematically equivalent linear relationship of an exponential EUE curve, should therefore be adopted.

Additionally, Edison defends the assumptions which it made in developing its proposed ERI. Edison first states that its ERI, in compliance with D.86-11-071, does represent a calculation using a group of QFs (150 MW) projected for 1988. Second, Edison asserts that its assumptions properly included the following legally binding agreement--the BPA MOU and the PP&L and PGE agreements discussed previously.

Edison contends that, in contrast to its own approach, PSD's proposal fails to meet the requirements of D.86-11-071 and fails to include consistent and appropriate resource assumptions. Edison points out that PSD's resource assumptions are neither consistent with the CEC ER-VI Report or with PSD's Resource Exhibit 51. Edison asserts that PSD has incorrectly excluded from its resource assumptions the Balsam Meadow and 550 MWs of Pacific Northwest Purchase. Edison states that, despite recognition of these errors, PSD failed to submit new or revised ERI values incorporating the needed changes.

Only Edison in this proceeding raised the issue of the status of suspended Standard Offer 2. Edison is very concerned that any reinstatement of the Standard Offer 2 levelized capacity payment schedule is premature and would present a significant risk of encouraging additional QF oversubscription. Edison therefore requests that the Commission defer from taking action on reinstatement of Standard Offer 2 until necessary modifications to the standard offer are given full and due consideration in A.82-04-044, et al.

(2) PSD

PSD states that at this time it does not have the ability to calculate an ERI based on EUE. PSD has, however, developed a different methodology which relies on the difference between a utility's actual reserve margin and its target or planning reserve margin.[17]

PSD acknowledges that its method is not the one mandated by D.86-11-071, but that it is simple and straightforward, easily replicable without recourse to computer models of any type, and achieves the goal of reflecting the value of additional capacity to the utility system. PSD further testified that its approach should capture the same basic effect as an EUE based ERI.

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17 In its testimony, PSD explained that its approach uses an actual reserve margin based on the utility resource plan, adjusted as appropriate to reflect the anticipated resource situation, and the load forecast adopted by the California Energy Commission in ER 6. The target reserve margin is also based on ER 6 figures for Edison. In applying this data, the PSD concludes that if the actual reserve margin is higher than the target reserve margin by 10 percentage points or more (e.g., actual reserve margin of 31% and target of 20%), the capacity value multiplier is set at zero. While the 10% figure is based on judgment, it is PSD's opinion that it was the reasonable range within which the corresponding EUE would drop to zero. If the actual reserve margin is equal to or less than the target, the multiplier is set at one. It is a linear scale between these two points.

With respect to its assumptions, PSD acknowledges the inadvertent, but erroneous exclusion of the capacity of the Balsam Meadow project, inclusion of certain erroneous figures for levels of cold standby, and use of a long-term, as opposed to short-term, demand forecast. PSD further acknowledges that it did not provide new ERI values to reflect the necessary corrections. PSD states, however, that it should be very clear that these values, while not themselves on the record, are derived using the Edison resource plan contained in Exhibit 16. PSD therefore believes that its formula for calculating the ERI can be modified according to record information.

(3) <u>CSC</u>

The CSC states that to determine the appropriate levels of as-available capacity payments for QFs, a choice must be made between the ERI methodologies presented in the record by PSD and Edison. If PSD's methodology is selected, corrections to PSD's assumptions, as acknowledged by PSD, must be made in order to calculate the appropriate ERI. If Edison's proposed ERI methodology is selected, additional determinations must be made concerning the viability of four individual resources. According to the CSC, PSD's "uncorrected" proposed ERI for 1988 is 5%. The CSC states that this figure would increase to 43% with the required adjustments. Edison's proposed ERI for 1988 is 4% which would change to a range between 37% to 72% depending on the treatment of the four questioned resource assumptions.

The CSC asks that its position in this proceeding not be taken as an endorsement or rejection of either methodology. With that in mind, the CSC concludes that for purposes of the general rate case Edison's calculation of the ERI, with adjustments to the four input assumptions as proposed by CSC, is preferable.

According to the CSC, the fundamental shortcoming of PSD's proposed ERI methodology in this proceeding is the use of an

inconsistent set of data. This inconsistence, in the CSC's view, serves to artificially deflate PSD's ERI calculation.

With respect to Edison's proposed ERI, the CSC states that Edison has presented an ERI methodology which relies upon a consistent and integrated set of data and employs an analytically supportable derivation of the EUE level. The CSC found that the flaws in Edison's calculation of the capacity value multiplier did not stem from the methodology, but from Edison's input assumptions related to supposedly firm, committed resource.

In the CSC's opinion, four resources have been erroneously included in the Edison's ERI analysis: (1) the BPA MOU, (2) the PP&L agreement, (3) the PGE agreement, and (4) 45 MW of as-available capacity from cogeneration resources. The CSC believes that the Commission has made clear in D.86-07-004 and D.86-11-071 that in determining a utility's ERI resources should be evaluated on a critical planning basis and that the "QF In/QF Out" methodology should be used. In the CSC's opinion, this "bare bones" assessment necessarily calls for the inclusion of only firm, committed resources which are likely to be available in terms of both physical availability and a reasonable price. The CSC concludes that the four questioned resources cannot meet this standard. We note that these three contracts and the CSC's position with respect to their being firm purchases have been discussed previously in our section on avoided energy costs.

With respect to the inclusion by Edison of 45 MW of as-available capacity as a firm resource, the CSC states that the Commission adopted EUE formula calls for an ERI which is equal to the average EUE, calculated with and without the block of additional capacity being valued (including the QF as-available capacity) divided by the EUE target. The CSC states that Edison admitted that no QF resource was taken out of its ERI calculation even though the resource to be valued was as-available QF capacity. In the CSC's opinion, the proper calculation of the ERI therefore

calls for the exclusion of the 45 MW of as-available QF capacity identified in the Edison resource plan.

According to the CSC, exclusion of the BPA MOU would increase Edison's ERI to 37%, with increases of an additional 6% for the exclusion of the 45 MW of QF as-available capacity, another 29% for the exclusion of the PP&L agreement, and a further 10% for the exclusion of the PGE agreement. The cumulative effect of these four adjustments would be to increase Edison's ERI to 82% in 1988.

3. Discussion

We adopt as reasonable the generation ($69.48/kW) and transmission ($33.10/kW) marginal demand costs jointly proposed by Edison and PSD, but with the O&M loading factor updated to better reflect O&M levels and adopted franchise fees in this general rate case. We find that these parties followed the appropriate methodologies in calculating generation marginal demand costs (unadjusted annualized value of a combustion turbine) and transmission marginal demand costs (regression analysis of transmission investment costs versus peak load increases).

We do not believe, however, that the record is sufficient in this proceeding to support CMA's proposal that generation marginal demand costs, like avoided capacity costs, should reflect an Energy Reliability Index. Specifically, we believe that further evidence is required to determine whether the concerns which lead to the adoption of an adjusted combustion turbine value for calculating QF capacity prices are the same for calculating marginal costs used in revenue allocation and rate design. We will, however, direct PSD and Edison to examine the issue of the propriety of reflecting the ERI adjustment in generation marginal demand costs in Edison's next general rate case.

With respect to the determination of Edison's avoided capacity costs, we believe that the starting point is the same as for the calculation of generation marginal demand costs--the annualized value of a combustion turbine. As noted above, PSD and Edison agreed to that value in Joint Exhibit 41.

However, our calculation of avoided capacity costs does not end with the adoption of this value. The Commission has made quite clear that an adjustment of the combustion turbine value is appropriate to reflect system reliability. Although final approval of the methodology to be used in making this adjustment for Edison is still to be resolved in A.82-04-44, et al., it is incumbent upon the Commission to adopt an adjustment factor in this proceeding based on the parties' proposals due to the absence of a "fall-back" position to be used in the interim. As stated earlier, in PG&E's most recent general rate case, the Commission was able to rely on the ERI which had been adopted in PG&E's previous general rate case. The absence of an adjustment of the shortage cost proxy in Edison's last general rate case prevents the Commission from following the same course in this proceeding.

Based on our decisions in A.82-04-44, et al., to date, we find that the Commission in D.86-07-004 and D.86-11-071 has indicated its preference for adjusting the annualized value of a combustion turbine by using an ERI based on an EUE target. In reviewing the proposals made in this proceeding, we note that PSD has urged the adoption of its target reserve margin methodology as being more straightforward and having the same effect as an EUE based ERI. We find, however, that the Commission has not yet endorsed a "proxy" for an ERI based on an EUE target. We also believe that it was PSD's, not this Commission's, responsibility to correct the assumptions which PSD made in calculating its capacity value multiplier and to provide the Commission with the final recommended adjustment. These steps, however, were not taken by PSD, and we are not inclined to complete PSD's showing in this decision.

Additionally, in this proceeding we have been presented with an ERI based on the concepts announced by the Commission in

D.86-07-004 and D.86-11-071. Although this proposal, which was made by Edison, may not have changed significantly since it was first proposed in A.82-04-44, et al., we find that without a "fall back" position it is sufficient for this proceeding. As noted by the CSC, Edison has presented an ERI methodology which relies upon a consistent and integrated set of data and employs an analytically supportable derivation of the expected unserved energy level.

We note, however, the several "flaws" which the CSC has identified in Edison's input assumptions used to calculate its ERI related to firm resources. Three of these assumptions we have dealt with in our section on marginal and avoided energy costs--the BPA MOU, the PP&L agreement, and the PGE agreement. We believe that our findings regarding the "firmness" of these agreements for purposes of calculating avoided energy costs are equally applicable here. As we stated in that section, our focus in determining Edison's obligation to purchase is on the status of the agreement as to the two parties involved, the acquisition of necessary government approval, and last, but least, the price negotiated. We conclude, as we did previously, that the BPA MOU appears to be uncertain from both of these standpoints with the parties having failed to even reach an agreement. As such the BPA MOU should not be included as an input assumption in calculating the ERI.

We find, however, that the PP&L and PGE contracts have attained greater certainty--agreements have been signed and proffered for governmental approval. Although questions of the propriety of the price Edison is to pay for this power did arise, we do not believe the evidence is sufficient to warrant a finding that the resource will not be available or that Edison is not committed to purchase the power. We therefore find that the PP&L and PGE contract were properly included as input assumptions.

Finally, the CSC correctly notes that in D.86-11-071 we determined that the ERI should equal the average EUE calculated with and without the block of additional capacity being valued,

divided by the EUE target. (D.86-11-071, at p. 9.) Since the capacity being valued in this proceeding is QF as-available capacity, we concur with the CSC that Edison erred by failing to remove any as-available QF resources from its ERI calculation. We therefore adopt the CSC's recommendation of excluding 45 MW of as-available capacity from this calculation.

The results of adopting the CSC's recommendation of excluding the BPA MOU and the 45 MW of as-available capacity is to raise Edison's proposed ERI from 4% to 43%. An ERI adjustment factor of 0.43 for 1988 is therefore adopted. [18] This value will remain in effect until updated or revised as prescribed in A.82-04-44, et al.

Finally, we respond to Edison's concerns regarding reinstatement of Standard Offer 2. As Edison has correctly noted, the reinstatement of Standard Offer 2 is an action specifically reserved to A.82-04-44, et al., and will not be decided in this proceeding.

E. Marginal Distribution and Marginal Customer Costs

1. Background

As explained in the previous section, marginal distribution costs are one of the three components of the marginal cost of demand. Marginal customer costs are the costs of providing access to the utility system to an additional customer and the costs of maintaining existing customers on the system. Marginal customer costs are not intended to reflect either energy consumption or capacity demand.

Both by definition and method of calculation, marginal distribution and marginal customer costs are distinct concepts. However, because the costs of customer access to the system (a

18 We note that the CSC has pointed out that PSD's "corrected" ERI would similarly be 43% for the test year as well.

marginal customer cost) include some elements of the electric distribution system, for this purpose these two types of marginal costs must be examined together. Specifically, the Commission must determine which of those distribution costs are demand-related and which are customer-access related and if such a determination, given current accounting data, can be made.

The need to examine the separate components of marginal customer costs has arisen due to our decision in PG&E's ECAC proceeding which adopted marginal costs for PG&E's test year 1987. (D.86-08-083.) In that decision, we abandoned our previous policy of including customer costs with other costs and allocated them on a demand basis to each customer class. We determined that it was appropriate to separately identify and allocate customer costs, which are a function of the number of utility customers and not demand or energy.

In undertaking this task, we needed to resolve two issues: (1) the appropriate methodology for determining customer costs, and (2) the appropriate classification of costs as either customer-related or demand-related. For methodology, we concluded in D.86-08-083 that "a weighted average of the incremental cost for new customers and the decremental cost for existing customers... reflects the marginal customer costs attributable to each customer class." (Id., at p. 49b.) We defined the incremental cost as those costs which the utility would incur in adding a new customer, and the decremental cost as those costs which the utility would not incur if an existing customer were to leave the utility system. (Id., at p. 49a.)

In the absence of a weighted average of incremental and decremental customer costs in the PG&E proceeding, we selected the

PSD new customer profile[19] as the "best available proxy" for that number. We stated, however, that "[i]n future proceedings with a more fully developed estimate of both incremental and decremental costs, we anticipate relying on the weighted average method ... to estimate marginal customer costs." (Id.)

With respect to the identification of marginal cost components, we found the following list of customer-related costs appropriate at present for inclusion in determining marginal customer costs for revenue allocation:

1. New customer access costs including meters, service drops, and final line transformers.[20]

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19 PSD recommended the use of incremental new customer costs. PSD's method for determining marginal customer costs was a two-step approach called the Directly Assignable Cost (DAC) methodology. This approach involves the calculation of variable and fixed costs assignable to a customer class. In order to identify the customers for which specific meters, service drops, and final line transformers were dedicated, PSD developed a typical customer in each class.

20 In its approach, PSD asserted that for the residential and small light and power customers, final line transformers would be classified as demand-related costs. In D.86-08-083, we found PSD's DAC methodology to be the best measure of marginal cost and adopted PSD's estimate of new incremental costs to be the proxy for the weighted average incremental/decremental cost approach endorsed by the Commission. Our use of PSD's estimate was premised on the belief that the estimate was quite conservative since it did not include line transformer costs in customer costs. The Commission learned, in a petition for rehearing of D.86-08-083 filed by TURN, that this assumption was in error and that PSD had included line transformer costs in customer costs. In D.87-05-087, we granted limited rehearing and directed PSD to recalculate and make available for comment its incremental new customer cost estimate allocating line transformer costs to demand costs rather than customer costs.

2. Replacement and improvement costs for existing customers' access equipment which includes the items above.

3. Distribution equipment which is directly assignable to a customer class.

4. Expenses which are related to meter-reading, record-keeping, and billing. (D.86-08-083, at p. 50.)

We also determined that further study of marginal customer costs was warranted. To this end, we directed PSD and PG&E to examine the subjects of record-keeping, the division of non-dedicated distribution equipment between access and demand functions, and the replacement and upgrading costs for access equipment. (Id., at pp. 51-52.)

2. Parties Positions

In this proceeding, the primary focus of the parties was on the appropriate allocation of costs between demand-related and customer access-related costs. The appropriate methodology for calculating marginal customer cost was also an issue, but no party presented direct evidence supporting an estimate of the weighted average of incremental and decremental customer costs as discussed in D.86-08-083.[21]

21 During hearings in this proceeding, TURN, who had not presented any direct showing on marginal customer costs, requested to submit rebuttal testimony to PSD's showing. Although no other interested party or PSD was given the opportunity to present rebuttal testimony, the presiding ALJ reluctantly granted TURN's request. In its "rebuttal" testimony, however, TURN sought not only to refute statements made by PSD, but also to introduce a proposed method of calculating decremental costs and a proposed weighted average of incremental/decremental costs using PSD values and TURN's decremental cost approach. Because this testimony was in fact a direct showing, for which ample time and opportunity had been given TURN, and not rebuttal to PSD's testimony, it was not

(Footnote continues on next page)

a. Edison

With respect to the distribution component of marginal demand cost, Edison states that both Edison and PSD used a regression analysis of demand-related distribution investments versus peak load increases to calculate the distribution marginal demand costs. Both parties assumed the demand-related distribution investment costs to be the portion of the total incremental distribution investment costs that remains after removing the customer-related investment. Despite differences in opinion regarding the appropriate methodology for allocating demand and customer access costs, Edison adopted the PSD's results which were not substantially different from its own.

Edison disputes CMA's claim that the marginal demand costs recommended by PSD and Edison are overstated because the noncoincident demand on the distribution system (represented by the sum of maximum demands on the distribution substations) was not taken into account in the PSD/Edison regression analysis. Edison understands that PSD did account for the overstatement caused by the use of system peak demand in its calculation by applying a factor which recognizes the relationship between noncoincident distribution demand and system peak demand.

In calculating marginal customers costs, Edison used the minimum distribution system (MDS) method adopted by the Commission

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(Footnote continued from previous page)

received into evidence. If the testimony of TURN had been heard, TURN would have been permitted an advantage that no other interested party or PSD, especially in the context of a general rate case schedule, would have or could have been granted. Further, all parties to the proceeding would have been denied the opportunity to respond to or rebut TURN's "direct showing."

in D.92749 (OII 67).[22] Edison explains that a minimum distribution system is a hypothetical distribution system consisting of the minimum-sized components which would electrically connect customers to the Edison system and would be capable of carrying only minimal load. Since, under this method, components are minimally sized, the costs associated with the minimum distribution system are assumed to be customer-related. The determination of the marginal customer costs affects the distribution marginal demand cost which is assumed to be the distribution investment costs that remain after removing the customer-related distribution investment costs.

On the basis of accounting data alone, it is Edison's opinion that the distribution marginal customer costs cannot be separated from the distribution marginal demand costs for joint cost components such as poles, lines, and towers. Edison allocates such joint costs to customer costs on the basis of the minimum distribution system. While agreeing that there are difficulties in properly allocating the joint costs, Edison believes that PSD's methodology understates customer costs by assuming that these cost components are all demand-related costs.

Edison determined, however, that even though the methodologies proposed by Edison and PSD differed, both were largely judgmental and led to similar marginal cost results if Edison were to remove the joint costs from the calculation. On that basis and to avoid unnecessary controversy, Edison accepted PSD's marginal customer costs for this proceeding.

With respect to the incremental/decremental method of calculating marginal customer costs, Edison states that this method will not recover 100% of an incremental new investment for the

22 This method was discussed, but largely opposed by the parties to the PG&E test year 1987 general rate case. (See D.86-08-083.)

residential class and should therefore be rejected by the Commission. Edison also objects to the Commission's consideration of the incremental/decremental method in this proceeding since it was not the subject of direct testimony and was supported in TURN's brief by arguments presented for the first time in this proceeding.

Edison also asks that the Commission reject the proposal of the Farm Bureau. Edison states that the Farm Bureau has requested that agricultural and pumping customers should not pay the same marginal customer cost as other customers due to the decrease in consumption of agricultural customers. Edison states that the effect of adopting such a proposal would be contrary to the adopted principle of marginal cost as a measure of the total cost change resulting from a change in output variables. Edison believes that it is entirely appropriate to require that agricultural and pumping customers pay the same marginal costs as other customers. Edison also notes that, despite the Farm Bureau's assertion to the contrary, PSD did determine the marginal customer costs for a typical agricultural customer based on data supplied to PSD by Edison.

b. <u>PSD</u>

In this proceeding, PSD recommends that marginal customer costs should be calculated on the basis of the typical customer approach adopted for PG&E's test year 1987 in D.86-08-083. This approach, according to PSD, identifies final line transformers, connecting service, and meters as customer access equipment. In this proceeding, PSD refers to its methodology as the "Transformer, Service Drop, and Meter" or TSM approach.

PSD further recommends the use of incremental marginal customer cost in determining marginal customer costs. It is PSD's opinion that the weighted average incremental/decremental cost methodology adopted in D.86-08-083 does not properly reflect marginal customer costs due to the systematic undercollection of plant investment which results from its use.

According to PSD, the fundamental advantages of the TSM approach are that it (1) provides a logical allocation of distribution plant between customer dedicated and common functions, (2) uses clearly assignable accounting information, and (3) yields clearly defined verifiable cost estimates. PSD asserts that those components of the distribution system which are dedicated to access by customer class include transformers (customers vary by voltage level), service drops (each customer has one for its sole use) and meters (each serves one customer). PSD points out that these components are typically sized according to the customer class virtually irrespective of load. In PSD's opinion the balance of the distribution components, referred to as the "common distribution system" (towers, poles, and lines), are shared by all customers, are sized according to expected load, and are therefore demand-related costs. PSD states that it also used an estimate of Edison's overall cost of capital to estimate annual charges for customer access equipment.

Until more accurate estimates can be determined, it is PSD's position that its proposal should be accepted as a very reasonable and balanced estimate of customer access costs. PSD notes, however, that other parties critical of the TSM approach have argued (1) that the approach fails to reflect any portion of the common distribution system (non-TSM) costs that are access-related, (2) that it does not reflect differentials in the rates at which different customer classes have added customers, and (3) that it fails to reflect only the costs of changes in customer access (the incremental/decremental method).

With respect to the first criticism, PSD acknowledges that because of geographic diversity among customers, some portion of the common distribution system is related to providing access to remotely located customers and is not exclusively demand-related. PSD states, however, that further study is required to provide the

proper means of precisely allocating common distribution system costs.

PSD states that the second area of concern with its approach was raised by the Farm Bureau. According to PSD, the Farm Bureau asserted that marginal customer costs should be decreased for customer groups, such as agricultural and pumping customers, whose numbers are decreasing. PSD points out that the difficulty with this approach is that the marginal customer costs are calculated by using the costs of adding a new customer in order to establish the marginal cost. The marginal cost value is therefore not derived from depreciated costs on an individual customer basis.

The third objection to PSD's approach stems from TURN's assertion that marginal customer costs should be computed using the incremental/decremental method. As noted previously, it is PSD's opinion, however, that the TURN approach has one basic and fundamental flaw--the systematic undercollection of plant investment.[23]

PSD states that it does not object to the incremental/decremental method because it may not exactly yield the revenue requirement, a goal which PSD agrees with TURN is not the purpose

23 According to PSD, TURN estimates the system rate as a weighted average of the full annual access equipment charge for new customers and 25% of the full annual rental charge for existing customers. PSD states that both PSD and TURN use an annual rental charge which would just amortize an investment if applied for each and every year of the service life of the investment. This annual charge is the economic carrying charge which remains constant in real dollar terms and would represent a good approximation of a competitive market's annual rental charge. PSD applies this charge every year to every customer as it must be if investment costs are ever to be recovered. The incremental/decremental approach proposed by TURN systematically reduces the annual charge for rate determination to 25% of its necessary value whenever a customer is reclassified from "new customer" to "existing customer", which will happen with each successive rate case; thus systematic undercollection is inevitably guaranteed.

of marginal cost pricing. Rather, PSD objects to the method because it contains an error which invariably causes under recovery of investment costs over the service life of the capitalized investment. PSD believes that any representation of marginal cost pricing which must necessarily forfeit investment is a defective representation of an otherwise useful pricing theory.[24]

Finally, PSD asserts that marginal customer costs for streetlighting should be developed using the same TSM methodology that PSD has used in calculating marginal customer costs for all other customer groups. PSD notes, however, that this analysis is distinct from the calculation of streetlight facilities charges which represent the rental fee for the streetlight appliance and which PSD recommends should continue to be excluded from the revenue allocation process.

PSD and Edison have agreed on the TSM marginal customer cost components for streetlighting except for the cost of a Regulated Output (R.O.) transformer. Specifically, PSD has proposed to allocate part (10%) of the cost of the transformer as a marginal cost, while allocating the remainder as a facilities charge. PSD states that it has no objection to the Commission classifying the full cost of the transformer as a marginal customer cost, a position which Edison believes is more consistent with PSD's TSM approach. PSD believes, however, that its allocation more appropriately reflects the fact that the R.O. transformer has aspects of both an end-use appliance and a means of customer access. PSD states that its allocation is therefore based on the

24 PSD also notes that the marginal costs of generation demand, transmission demand and distribution demand all contain an investment component which is amortized by an annual economic carrying charge. PSD states that TURN has never explained why an incremental/decremental estimate should not also be applied to these other marginal costs.

difference between the cost of a standard transformer which provides "access" and the cost of an R.O. transformer which provides "access" as well as the regulated output necessary to the proper functioning of the streetlight.

c. <u>CMA</u>

It is CMA's position that Edison erroneously agreed to PSD's marginal distribution and marginal customer cost values. CMA states that witnesses for both PSD and Edison acknowledged that some part of the common distribution system is necessary for customer access. Yet, according to CMA, PSD allocated zero percent of that system as customer costs, while Edison's original method would have allocated 40% of that system to customer costs. CMA believes that access costs must be distinguished and allocated as customer costs, not demand costs. In CMA's opinion, Edison's original minimum distribution system analysis remains the best in this record for achieving that goal.

With respect to marginal distribution demand costs, CMA observes that PSD has determined annual marginal distribution demand costs at $37.91/kW. In its testimony, CMA concluded that a comparable cost was $22.63/kW at secondary voltage and $19.53/kW at primary voltage. CMA states that the source of the difference is in the direct incremental investment which CMA determined was $115.04/kW while PSD determined was $228.00/kW. CMA believes that, in major part, this difference is generated by PSD's allocation of all the common distribution system to demand costs instead of allocating 40% as a customer cost as Edison originally did and CMA submits is correct.

In addition, CMA contends that the appropriate load on which to regress the distribution demand costs is not system peak demand, as PSD did, but the demand on the distribution system as measured by the sum of the maximum demands on distribution substations. CMA believes that such a method is more accurate by analyzing demands on each distribution substation. CMA notes,

however, that its approach could have been improved by data from substations being accumulated by Edison in a more complete form.

d. Industrial Users

Like CMA, the IU objects to PSD's marginal customer cost proposal on the basis that it allocates all of the costs of the common distribution system to demand and none to customer costs, even though it is undisputed that the distribution system serves both a load and access function. The IU believes that the effect of this error was demonstrated by their witness who compared the total marginal costs for Edison's major customer classes incorporating, first, the PSD's customer costs and second, Edison's originally proposed customer costs which included 40% of common distribution costs. The IU states that this comparison revealed that, by using the Edison values, the result would be a marked increase in the amount of the costs allocated to residential customers and a decrease in the costs allocated to all of the other major customer classes, large power included.

IU, however, stops short of endorsing Edison's approach. Instead, in its testimony, IU proposed two alternate methods (the minimum customer method and the zero intercept method) which are variations of the MDS method. According to the IU, time constraints prohibited the refinement of marginal customer cost data in this proceeding using either of these approaches. IU therefore asks that if the allocation of revenue adopted in this case is to be phased-in over more than one year, any revenue allocation after the initial allocation be based on a marginal cost study that attempts to more accurately estimate the full level of marginal customer costs.

e. Farm Bureau

The Farm Bureau states that marginal cost pricing, in theory and as adopted by the Commission, is a method which measures how a change in a variable component of providing electric service affects the total cost of the electric service. To remain true to

the marginal cost methodology of pricing the total electric service on the margin, the Farm Bureau states that each component (i.e., demand, energy, and customer costs) must be measured on the margin.

The Farm Bureau believes, however, that this analysis distorts the true cost of service for any class of customers who are not causing the variables of demand, energy, or customer to increase. In the Farm Bureau's opinion, a marginal cost pricing formula which fails to consider the fact that a "plateauing" of a class of service creates a counter-balancing effect on that class's demand, energy and/or customer costs will cause the class to receive a cost allocation above its true cost of service.

It is the Farm Bureau's position that the Commission should amend its marginal cost pricing methodology to recognize the proposition that increases which are caused by specific groups of customers must be billed directly to those customers. Until that time, in the Farm Bureau's opinion, a class of service remaining constant or lowering its demand, such as the agricultural class, will receive cost allocations which it did not cause the system to incur.

According to the Farm Bureau, for demand costs, the matching of causation and cost dictates that new additions be charged to those customer classes causing the new load. For customer costs, Farm Bureau states that both PSD's and Edison's calculations fail to recognize the significant decrease in agricultural customers in over the last ten years and the retention by the agricultural class of transformers, service drops and meters far beyond their book life.

f. <u>TURN</u>

TURN opposes the calculation of marginal customer costs based on the costs of adding new customers to the Edison system. TURN states that the cost of adding new customers to the Edison system (incremental customer cost) is much greater than the cost saved by the utility when an existing customer leaves (decremental

customer costs). Basing revenue allocation on incremental customer costs therefore sends the wrong price signal as it overstates the savings to the utility when a customer leaves the system.

It is TURN's position that if marginal customer costs are to be used in this proceeding, the Commission should follow the incremental/decremental approach adopted for PG&E in D.86-08-083 and recently reaffirmed on rehearing in D.87-05-076. In TURN's opinion, this approach is a better proxy for the economically efficient method of charging new customers a hook-up fee and existing customers decremental customer costs. TURN further notes that in D.86-03-083, the Commission recognized that using incremental customer costs in revenue allocation provides an inaccurate price signal to existing customers (D.86-08-083, at p. 49).

TURN also responds to PSD's claim that blending incremental and decremental cost will result in revenue undercollection. TURN states that PSD's objection is irrelevant because the purpose of marginal cost pricing is to provide accurate price signals and not to recover the utility's investment. TURN also argues that PSD has also dramatically overstated the amount of revenue shortfall assertedly caused by the incremental/decremental approach by using a model which fails to recognize that the number of existing customers far exceeds the number of new customers on the Edison system. Moreover, TURN states that the shortfall only exists if rates are set exactly at marginal cost. If rates are set on the basis of Equal Percent of Marginal Cost (EPMC), TURN believes that there may be not shortfall at all from using the incremental/ decremental method.

TURN also asserts that all parties except itself have overstated incremental marginal customer costs. According to TURN, the PSD method of calculating marginal costs incorrectly assumes that customers would rent interconnection equipment from utilities rather than purchase this equipment. Since the cost of purchasing

equipment is clearly lower than the rental cost assumed by the PSD, TURN believes that utilities would be forced by competition to offer rates below the PSD's incremental rental rate.

Despite PSD's arguments to the contrary, TURN does not believe that customer ownership of access equipment presents any insurmountable problems. According to TURN, requirements of safety, reliability and billing integrity could all be met by allowing customer access equipment to be serviced only by qualified companies and limiting meter servicing, if necessary, to the utility.

Finally, TURN notes that in granting its request for rehearing of D.86-08-083, the Commission ordered the PSD to recalculate incremental customer cost by omitting the cost of transformers (D.87-05-076). Based on Table 4-1 of PSD's Exhibit 60-D, TURN states that, by removing transformer costs, which PSD did not do in calculating its incremental marginal customer costs, the residential customer cost proposed by PSD would be lowered by approximately one-third.

3. Discussion

It had been our opinion that in D.86-08-083 we had reached certain significant and final conclusions regarding the use and determination of marginal customer costs. Specifically, in that decision we found, as recited at the beginning of this section, (1) that marginal customer costs should be included in the revenue allocation process, (2) that the weighted average of incremental and decremental costs should be used to calculate marginal customer costs, and (3) that customer-related costs should include meters, service drops, and final line transformers; the costs of replacing and improving such access equipment; and distribution equipment directly assignable to a customer class.

While the parties to this proceeding have followed our direction in D.86-08-083 with respect to two of these findings, all, except for TURN, have ignored the Commission's statement that

in future proceedings "we anticipate relying on the weighted average method to estimate marginal customer costs." (D.86-08-083, at p. 49b.) In this case, we have been presented with no direct evidence or "a fully developed estimate" of both incremental and decremental costs nor, obviously, a weighted average of those costs.[25] Instead, the record in this proceeding includes only the following: (1) Edison's use of the MDS approach which we did not adopt in D.86-08-083 to calculate marginal customer costs; (2) PSD's proposed incremental customer cost estimate, a cost which was adopted in D.86-08-083 as a "proxy" for incremental/decremental cost approach only because of the absence of a weighted average of those two costs; (3) Farm Bureau's proposed retreat from marginal cost pricing for agricultural and pumping customers; and (4) TURN's endorsement of the incremental/decremental approach unsupported by any direct evidence on the calculation of those costs.

In response to arguments that the incremental/decremental method will undercollect the revenue requirement, we concur with TURN that the question of revenue shortfalls is not necessarily relevant in determining the appropriate methodology for calculating marginal costs. As we have repeatedly stated, marginal costs are used in ratemaking in order to provide the most accurate price signals regarding the customer's electric consumption. In adopting the incremental/decremental approach, we believed and remain convinced that this goal is achieved by relying on a methodology which most precisely determines the marginal cost related to customer access and maintenance on the utility system.

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25 We note, for Edison's benefit, that its customary argument that prior rate cases of other utilities are not precedential with respect to its own general rate case does not apply here. As our review of D.86-08-083 makes clear, that decision was clearly intended to have precedential effect.

Further, as noted previously, we have no "fully developed" estimates of the incremental cost for new customers and the decremental cost for existing customers. Without these estimates, it is difficult to make the required comparison between the PSD's approach and the weighted average incremental/ decremental approach which we adopted in D.86-08-083 to determine whether and to what extent systematic undercollection is caused by using this latter methodology. We note that Edison's and PSD's concerns regarding revenue shortfalls appear to relate more to TURN's approach to calculating decremental costs than to fundamental problems with the weighted average methodology itself. If this circumstance is in fact the case, we note that neither PSD nor Edison is in any way precluded from taking into account and adjusting for the potential for undercollection in determining its estimates of incremental and decremental customer costs in future proceedings.

We also reject the Farm Bureau's apparent attempt to return to embedded costs to measure the customer costs to be attributed to agricultural customers. Whether a class is increasing or decreasing, we have concluded that the most equitable way in which to determine class revenue responsibility is by viewing the impact of such changes not in isolation, but in terms of their effect on a utility's total costs. If the Farm Bureau believes that some "special treatment" of agricultural customers is warranted, this goal is better achieved within the specific rate schedules under which those customers' rates are determined.[26]

26 We note that the Farm Bureau has identified certain costs (i.e., those associated with noncoincident demand) as not among those imposed on the utility system by the agricultural class. We are concerned, however, that, in order to be consistent, if other costs, such as those related to access, were borne entirely by the

(Footnote continues on next page)

Given the choices that have been presented in this proceeding, it appears that only PSD has provided us with a "usable" proxy for the weighted average of incremental and decremental costs. Specifically, we find that PSD's determination of incremental costs based on the TSM approach is closest to the intent of D.86-08-083.

As we mentioned previously, however, our adoption of PSD's approach for PG&E was premised on PSD's incremental marginal customer cost estimate being conservative. We concluded that this conservatism had resulted from PSD's treatment of final line transformers for the residential and small light and power customers as demand-related costs. A limited rehearing of D.86-08-083 was necessary to ensure that numbers reflecting this treatment of line transformers were used in determining PG&E's marginal customer costs.

To bring Edison's marginal customer costs closer to those intended to be implemented following D.86-08-083, we will also adopt PSD's incremental customer cost estimate exclusive of final line transformers as the proxy for the weighted average of Edison's incremental and decremental customer costs. We do not find, however, a basis to discriminate between classes for purposes of this exclusion and will use an incremental cost estimate which excludes the line transformers for all customer classes. This approach will ensure equal treatment of all customer classes in the revenue allocation process.

(Footnote continued from previous page)

agricultural class in proportion to their being incurred by that class, a significant burden would be created for agricultural customers which is otherwise currently offset by our use of marginal costs.

We find that, by ordering the removal of transformer costs, the resolution of the marginal customer cost issue for Edison will be similar to that which we adopted by PG&E. For the next general rate cases of each electric utility, we direct all parties to follow and provide numerical estimates based on the methodology adopted in D.86-08-083 and reaffirmed in this order based on the weighted average of the utility's incremental and decremental customer costs. Once these costs are properly before us in future proceedings, it will hopefully no longer be necessary to rely on a proxy which excludes an otherwise properly recognized customer access cost (i.e., final line transformers) from the calculation of marginal customer costs.

We also find that until further studies are completed PSD has made a good faith effort to attribute those costs to customers which are directly assignable to customer access. PSD has followed the list which we adopted in D.86-08-083 and has continued to include distribution costs for which combined demand and customer-access functions cannot now be accurately segregated.

We also concur with PSD's approach to calculating marginal customer costs for streetlight customers and PSD's inclusion of those costs in the revenue allocation process. We believe that PSD's effort to differentiate between the dual functions of the R.O. transformer (access-related and end-use-related) is appropriate. This approach is not only consistent with our efforts to specifically identify marginal customer costs, but also with our continued exclusion from the revenue allocation process of streetlight facilities charges as costs associated with an end-use.

Finally, we are not insensitive to the concerns of the industrial customers regarding the need to ensure that all costs, even those also related to distribution, be properly included in marginal customer costs. To this end and recognizing the need for further refinements in the development of marginal customer costs, we direct Edison to work with PSD to:

> "1. Establish record-keeping that will clearly
>
> (1) identify customer hook-up costs and
>
> (2) distinguish new from existing customers.
>
> "2. Analyze non-dedicated distribution equipment for access versus demand function.
>
> "3. Identify replacement and upgrading costs for access equipment." (D.86-08-083, at p. 52.)

With respect to the calculation of marginal distribution costs, we adopt the agreement reached by PSD and Edison modified, as necessary, to reflect our adopted marginal customer costs exclusive of transformers. Edison and PSD appropriately utilized a regression analysis of demand-related distribution investments versus peak load increases to calculate the distribution marginal demand costs. For Edison's next general rate case, we will direct PSD and Edison to examine the effects of basing the regression on the load measured by the sum of the maximum demands on distribution substations as proposed by CMA. As stated previously, we have endorsed PSD's approach to classifying demand and customer access costs which produced distribution marginal demand costs to which Edison acceded.

F. <u>Costing Periods</u>

In this section, we will adopt the appropriate basis upon which to differentiate marginal costs on the basis of time-of-use (TOU) or costing periods. A costing period is defined as a group of contiguous hours which are combined and treated as a single unit when allocating system costs and developing a rate design. Time-differentiated marginal costs are an important factor in developing rate design, evaluating conservation and load management programs, and making other resource decisions.

The goal in establishing costing periods is to group hours by time of day and by season so as to maximize differences in the costing patterns between periods and minimize the differences between hours within periods. Data taken into account in determining the appropriate costing periods include marginal costs, load curves, loss of load probabilities, and excess load probabilities. Consideration is also given to the ease of customer understanding of the periods, the continuity over time, the ability to avoid rate shock solely from changing time periods, and the degree of administrative burden imposed on the utility from any changes.

1. Parties Positions

a. Edison and PSD

In Exhibit 41, jointly sponsored by Edison and PSD, these two parties compromised on a proposal to modify the existing TOU periods for cost analysis and rate design purposes. Both parties had originally sponsored independent proposals based on analyses of 1988 loads, hourly marginal cost, and loss of load probability data. The proposal to which Edison and PSD agreed would merge the existing winter on-peak and mid-peak TOU periods, leaving unchanged the other TOU periods.

According to Edison and PSD, during the hearings the only party to express concern with the proposed costing periods was the CLECA/CSPG. Through their cross-examination of the PSD and Edison witnesses sponsoring Exhibit 41, these organizations indicated a preference to shorten the summer on-peak period as originally proposed by PSD. In reply, Edison testified that the shortening originally proposed had not been based on unequivocal data and could bring about load shifting that would require a longer on-peak period in the next general rate case.

Both Edison and PSD note that no party, however, made any affirmative request for costing periods different than those identified in Exhibit 41. Edison and PSD therefore ask the Commission to adopt their joint proposal to merge winter on-peak and mid-peak costing periods.

In its brief Edison also responds to a proposal made by IEP during the hearings, not with respect to costing periods for marginal costs, but with respect to the development of a "super off-peak" period for avoided cost pricing for QFs. IEP's recommendation, which is based on producing more accurate price signals, would consist of adding a super off-peak period for QFs for the hours from 1:00 a.m. to 5:00 a.m. every day.

Edison believes, however, that the results of IEP's analysis do not support its recommendation. Edison states that IEP had found the difference between avoided energy cost in the off-peak and super off-peak periods to be only 0.05 cents/kWh in the summer and 0.06 cents/kWh in the winter. Edison concludes that this small differential between costs in the off-peak and super off-peak periods does not justify the change requested by IEP.

b. <u>CMA</u>

CMA states that time-differentiated costs are particularly susceptible to variations in data. For this reason, CMA is concerned that current procedures for determining costing and rating periods are "highly judgmental." CMA therefore urges the Commission to consider more formally articulated principles for developing costing periods.

c. <u>CLECA/CSPG</u>

CLECA/CSPG agree with the position of PSD and Edison, as set forth in Exhibit 41, that current cost data supports consolidation of winter on- and mid-peak TOU periods into a single mid-peak period. CLECA/CSPG indicate their concern, however, with the failure to completely analyze the merits of reducing the summer on-peak TOU period to five hours from six hours, as first proposed by PSD. CLECA/CSPG believe that this issue should be considered more fully in the next Edison general rate case to determine whether a shorter summer on-peak period is viable for large power customers.

2. Discussion

The need for time-differentiated marginal costs is clear. By adopting such an approach, TOU customers will be provided with the most accurate price signals regarding their electric consumption and can in turn make informed economic decisions about that consumption. We do not in this proceeding, however, have a record on which to base any refinements to costing periods beyond those to which Edison and PSD have agreed. We encourage CMA, CLECA/CSPG, or any other interested party, as well as PSD and Edison, to provide us with information in Edison's next general rate case aimed at improving the judgmental science of developing costing periods and in turn furthering our goal of marginal cost ratemaking. Such an inquiry could include an examination of whether a shorter summer on-peak period is viable for large power customers as suggested by CLECA/CSPG.

Until that time, we will adopt the costing periods to which PSD and Edison have agreed in Joint Exhibit 41 which include the single change of combining the winter on-peak and mid-peak periods. We concur with Edison, however, that the record does not support the addition of a super-off-peak period for QFs on Edison's system at this time. This finding does not preclude IEP or other interested parties, however, from renewing this proposal in Edison's next general rate case.

G. Adopted Marginal Costs

Marginal costs, once determined by the Commission, are ultimately used to apportion the adopted revenue requirement among customer classes. The following table presents our adopted annual marginal energy, demand, and customer costs.

SOUTHERN CALIFORNIA EDISON COMPANY
SUMMARY OF ADOPTED MARGINAL COSTS
TEST YEAR 1988

MARGINAL ENERGY COSTS	($/kWh)
Generation	0.0273
Transmission	0.0280
Distribution:	
Primary	0.0290
Secondary	0.0295
MARGINAL DEMAND COSTS	($/kW/YEAR)
Generation	69.48
Transmission	33.10
Distribution:	
Primary	45.06
Secondary	52.22
MARGINAL CUSTOMER COSTS	($/CUSTOMER/YEAR)
Domestic	43.44
GS-1	43.10
GS-2	211.65
PA-1	128.53
PA-2	214.37
TOU-8-Secondary	1342.82
TOU-8-Primary	2139.68
TOU-8-Subtransmission	2139.68
LS-3-Primary	317.88
LS-3-Secondary	80.04
	($/LAMP/YEAR)
LS-1	3.10
LS-2-Primary	7.32
LS-2-Secondary	5.34
OL-1	3.40
DWL-A	3.40
DWL-B	3.40
DWL-C	0.00

X. Revenue Allocation

A. Introduction

Revenue allocation is the process by which the total adopted revenue requirement is divided up among the various customer classes (inter-class) and among schedules within a customer class (intra-class). For purposes of revenue allocation, Edison's ratepayers have been classified into the following customer groups: domestic, small and medium light and power, large power, agricultural and pumping, and street and area lighting. Issues related to revenue allocation include the methodology to be used in allocating the revenue requirement; the manner in which that methodology is to be implemented; and the propriety of applying the same methodology to both inter-class and intra-class revenue allocation and including all customer classes (i.e., streetlight customers) in the revenue allocation.

In recent years the Commission has adhered to a policy that, to the extent practical, total revenue should be allocated to ratepayers on the basis of their share of the utility's marginal cost. As explained in our prior section on marginal cost, we believe that the reliance on marginal cost principles achieves equity in rates by relating the costs imposed on the utility system to the customer responsible for those costs.

In determining the appropriate methodology to use in allocating revenues, the Commission has had to balance its goal of achieving marginal cost ratemaking against the potentially negative impact on certain customer groups of restructuring revenue responsibilities. Among the methods considered by the Commission over the last several years have been the Equal Percent of Marginal Cost (EPMC) approach, the System Average Percentage Change (SAPC) approach, and a weighted average combination of the two.

EPMC allocates the revenue requirement on an equal basis relative to the marginal cost-based burden each customer class

imposes on the system. SAPC adjusts existing revenue responsibilities for each customer class or schedule by the overall average percentage change in revenue requirement.

Most recently, for PG&E we concluded that our goal of marginal cost ratemaking could be achieved only by the adoption of the EPMC methodology for both inter-class and intra-class revenue allocation. In adopting a full EPMC methodology for PG&E, however, we recognized the need for moderating the effects which such an approach would have on certain customer classes. We therefore determined that the adopted EPMC revenue allocation should be phased-in prior to the next general rate case and that a cap limiting the percentage by which the average class rate could change over the SAPC for the forecast period (1987) should be used. Specifically, we found reasonable a 5 percentage point cap over the system average increase for classes other than agriculture, and a 2.5 percentage point cap over SAPC for agriculture. Based on the revenue requirement adopted in PG&E, the only classes which ultimately required any capping were the residential and small light and power (5%) and agricultural (2.5%) classes. (See D.86-08-083, at pp. 67 - 67a.)

In D.86-08-083, we concluded that our approach to implementing EPMC for PG&E would achieve our goal of a marginal cost-based revenue allocation without a significant detrimental impact on any customer class. Nevertheless, while we adopted a cap for the 1987 forecast period, we declined to adopt any caps in that proceeding for the 1988 and 1989 periods. Parties were given the opportunity to renew such proposals, if necessary, in subsequent PG&E ECAC proceedings.

Following D.86-08-083, we issued D.87-05-071 in R.86-10-001, the Commission's rulemaking on revisions to electric

utility ratemaking mechanisms.[27] In D.87-05-071, the Commission focused on rules aimed, among other things, at addressing the threat of customers' bypassing the electric utilities' systems in favor of self-generation.[28] Our particular concern, as explained in D.87-05-071, is that a customer with self-generation costs exceeding the utility's short-run marginal costs will bypass the utility system (uneconomic bypass). When this situation occurs, we have found that the customer's self-generation results in "an inefficient allocation of society's resources." (D.87-05-071, at p. 3.)

Included in the policies announced in D.87-05-071 to address the problems created by bypass was our endorsement of utility revenue allocations based on EPMC. We cited the following reasons as support for "embracing EPMC as a guiding principle for revenue allocation" (Id. at p. 5): (1) EPMC provides a fair way of relating each class's revenue requirement to the costs of providing service to that class; (2) EPMC helps reduce inter-class subsidies that distort price signals and thus result in inefficiencies to the detriment of society in general; and (3) EPMC is effective in bringing rates closer to marginal costs in precisely those customer classes most likely to bypass the utility system.

B. Adopted Revenue Allocation Methodology

Against this background, it is clear that we are fully committed to the EPMC approach for revenue allocation as the most accurate way to reflect costs customers impose on the system and as an effective response to the threat of bypass. Our intentions are

27 This proceeding is also known as the "3-Rs" (risk, return, and ratemaking) rulemaking.

28 The subject of bypass, to the extent that it affects this proceeding, is discussed in a separate section of this decision.

apparently well-known to the parties in this proceeding who almost unanimously endorsed an allocation of Edison's revenue requirement based on EPMC.[29]

Only one party to this proceeding, ACWA, endorsed a different approach. Specifically, ACWA recommended that class cost responsibility be based on an equal rate of return methodology. As Edison correctly points out this approach is based on the utility's embedded costs, a basis for ratemaking which the Commission has clearly rejected in favor of marginal cost. ACWA's arguments concerning the potential long-term negative impact on certain customer classes of adopting an EPMC revenue allocation could have been more constructively applied to proposals relating to the implementation of EPMC.

We therefore adopt in this proceeding a full EPMC approach for allocating Edison's revenue requirement. Our adoption of this methodology, however, as explained in the succeeding sections, does not end the discussion of revenue allocation. In fact, the use of EPMC requires the Commission to resolve such critical issues as the manner in which it will be implemented and the extent to which it will be applied to all customer classes and to all rate schedules within those classes.

C. Implementation of EPMC Revenue Allocation

It is the issue of implementation of a full EPMC revenue allocation for Edison which was the center of debate in this proceeding. The reason for this controversy is clear.

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29 The IU organization notes that while it has traditionally advocated the use of the utility's actual or embedded cost as the most appropriate basis for revenue allocation, it joins CMA, CLECA/CSPG, FEA, PSD, and Edison in supporting a revenue allocation based on full EPMC. IU states that its support is based on the substantial similarity in results of embedded cost and marginal cost-based analyses and the potential of an EPMC methodology providing accurate price signals and avoiding uneconomic bypass.

Specifically, the adoption of EPMC for Edison as the exclusive basis for revenue allocation, even if implemented over a period of years, will result in a significant rearrangement of revenue responsibility among Edison's customer groups. This impact is in part due to the historic allocation of Edison's revenues on a basis other than EPMC. In Edison's last general rate case, for instance, an allocation formula of a weighted average of 5% EPMC, 95% SAPC, was adopted. (D.84-12-068 at pp. 270-271.)

As a result, Edison's present rates are currently quite far from EPMC. Our move to EPMC could therefore result in significant increases to the domestic class and substantial decreases for the large power class. The Commission must consider if and to what extent these shifts in revenue responsibility should be mitigated in implementing EPMC.

1. Parties Positions

a. Edison

Edison has determined that it is necessary to mitigate the adverse bill impacts on certain customers that would result from an immediate implementation of a full EPMC revenue allocation methodology. To this end, Edison proposes a three-year phase-in plan resulting in a full EPMC revenue allocation by 1990.

Edison's phase-in proposal calls for three annual revenue allocation adjustments. The first of these would take place in the test year 1988 when the total January 1, 1988 revenue requirement, including the revenue requirement adopted in this proceeding, would be allocated on the basis of a weighted average of 2/3 SAPC and 1/3 EPMC. The revenue requirement for 1989 would be allocated on the basis of a weighted average of 1/3 SAPC and 2/3 EPMC, with full EPMC achieved by 1990. In support of its approach, Edison states that its phase-in methodology: (1) treats all customer and rate groups equitably and consistently since they all steadily converge on full EPMC; (2) is understandable and easily applied; and (3) best ensures the achievement of full EPMC within three years.

Edison has further proposed that the EPMC phase-in be implemented in the next two Attrition Rate Adjustment (ARA) filings (i.e, 1989 and 1990). Edison supports the use of the ARA proceeding because it is the forum in which a complete update of base rate factors is developed. According to Edison, the ARA is also based on a calendar year which more naturally fits with the forecast process of billing determinants and base rate costs. Edison rejects using the ECAC to implement the phase-in on the grounds that such an approach would unnecessarily complicate the already burdened ECAC proceeding.

With respect to PSD's proposed method of applying "caps" in phasing-in EPMC, Edison states that the adoption of this approach for PG&E in D.86-08-083 is not dispositive of the propriety of applying a similar methodology to Edison. Edison notes the following differences between the PG&E proceeding and the present one: (1) PG&E was requesting a significant decrease in revenues while Edison is requesting an increase, and (2) PG&E's present rate revenues were much closer to EPMC to begin with than are Edison's present rate revenues.

Edison further cites three shortcomings with the PSD approach. First, Edison states that PSD's methodology would result in some rate groups initially moving further away from EPMC. Second, Edison believes that it is unlikely that PSD can achieve its objective of reaching full EPMC by 1990, citing PSD testimony that an increase or decrease beyond a certain range would mean that full EPMC could not be reached using the proposed PSD caps. Third, Edison warns that PSD's proposal to forecast the third year's revenue requirement is an overly complicated process.

Edison also rejects the proposals of other parties, like CMA and FEA, who suggest a more rapid movement to EPMC. Edison believes that a more immediate move to full EPMC will result in severe bill impacts for such customer groups as general service and agricultural and pumping customers.

b. PSD

PSD proposes that a 100% EPMC revenue allocation be adopted, but, like Edison, suggests that the impact of this change in revenue responsibility be mitigated by implementing EPMC over the three-year general rate case cycle. PSD recommends that this end be accomplished by setting an 8% cap above the system average increase for the first year for all customer classes, and by setting the second-year class revenue requirements at the average of the revenue requirements in the first and third years.

PSD acknowledges that under its approach some classes may initially move further from EPMC than they currently are. PSD states that this result occurs due to the cap limiting the increases to some, primarily the domestic class, with the remaining revenue requirement being allocated to the other classes. PSD believes, however, that those customers who would potentially move in the "wrong" direction would also be those who would view investment decisions on a multi-year basis and would be able to view the allocation adjustment on a similar basis. PSD also noted that were the revenue requirement to be significantly higher or lower than the range between Edison's and PSD's proposals, the cap might require adjustment.

With respect to the forum in which the phase-in would be implemented, PSD believes that the ECAC proceeding is the most convenient place for this transition to take place. PSD states that production simulations are already conducted in ECAC, even though on a different year basis than the general rate case. Further, PSD asserts that ECACs are technical proceedings which already involve substantial hearing time, utilize the experts and information necessary to reestimate marginal costs, and currently involve allocation and rate design issues. (See, e.g., D.86-08-083 at 52; D.87-01-051 at 24.) PSD rejects the use of the attrition proceeding which, in PSD's view is intended to be a fairly simple

and expeditious proceeding, handled in "cookbook" fashion, which should not get bogged down in major allocation issues.

c. CMA

In CMA's opinion, for an extended period high rates charged to large power customers have shielded other customers from Edison's increasing costs. CMA states that the Commission itself has recognized the need to redress the inequities in the current revenue allocation by moving to EPMC revenue allocations. (D.86-08-083, D.87-05-071.)

CMA acknowledges that principles of rate stability justify a transition period to correct the inequities in the existing revenue allocation. CMA differs, however, as to the time required for this transition and the manner in which such a phase-in should occur. CMA suggests that with PSD's reduced revenue requirement, there is no reason to take three years for the transition. Instead, CMA recommends a two-year transition period using a 13% per year increase in domestic rates.

CMA also endorses a transition to EPMC by capped adjustments and not by reliance on SAPC as suggested by Edison. In CMA's view, the differences between these methods is not in the impact on the domestic customers, but in how quickly the large power customers are relieved of their burden of subsidizing other classes. CMA notes that under the capped increase method, rates for all other classes except GS-1 converge in 1988 upon approximately the same point at about 100% of EPMC. Using Edison's transition method, CMA asserts that major disparities in how the several classes bear the subsidy provided to domestic customers is perpetuated.

With respect to the appropriate forum for making transition adjustments to full EPMC, CMA concurs with the use of the ECAC proceeding as proposed by PSD. In CMA's view, the ECAC proceeding provides greater assurance of expeditious consideration of updated costs. CMA also notes that the continued existence of

the attrition rate adjustment proceedings remains at issue in R.86-10-001.

d. IU

IU asserts that two policy considerations require the earliest possible phase-in of full EPMC on the Edison system. These include the spector of further industrial bypass in response to Edison's excessive industrial rates and the relative impact on utility customers of revenue reallocation in the test year versus revenue reallocation in subsequent years. IU states that while a more gradual phase-in may tend to reduce rate shock for some customers, it also postpones rate relief for customers considering uneconomic bypass alternatives. IU also states that the Commission should carefully consider whether postponing rate adjustments to future years will, in fact, reduce rate shock.

With Edison's original revenue request of $302 million, IU proposes a cap of 21% as the maximum initial increase any customer class should receive with a maximum full three-year phase-in. Under PSD's $375 million decrease, IU recommends a 10% cap with a 100% EPMC reallocation to be attained within two rather than three years. Should the revenue requirement fall somewhere between these two recommended levels, IU presented a third revenue allocation option based on the level of Edison's present revenues. Under this scenario, a cap of 13% would apply, and the move to full EPMC would be accomplished in two rather than three years.

IU asks that any revenue allocation update occurring between general rate cases be ministerial in nature and not result in a full-blown recasting of marginal cost concepts, studies, or findings. With respect to procedural forum, IU endorses PSD's recommendation of the ECAC. IU believes that as ECAC has evolved over the years, this type of proceeding offers the most promising time frame and hearing resources for this kind of issue. IU believes that this position is further enhanced by the Commission's forthcoming elimination of the attrition proceedings, a type of

proceeding the Commission has expressed a great desire to handle in cookbook fashion, quickly with few hearings.

e. FEA

FEA urges this Commission to recognize that movement toward marginal cost-based revenues should be systematic, should present consistent signals to Edison's customers, and should be as rapid as possible. FEA finds numerous problems in this regard with both Edison's and PSD's revenue allocation proposals.

According to FEA, the Edison formula is flawed because it allocates first-year increases to several rate classes that deserve revenue decreases, ignores the need to move classes toward cost in an absolute sense, and fails to produce a systematic or logical pattern of movement toward marginal cost revenue allocation. FEA recommends rejection of PSD's recommended approach on the bases that is not sensitive to the level of revenue increase granted and produces erratic movement toward EPMC revenues.

FEA therefore recommends that the Commission attempt to eliminate at least 50% of existing revenue subsidies in the test year. FEA further recommends that caps should be established to constrain revenue increases and decreases in each step and that the Commission should avoid allocations that do not consistently move toward cost-based revenues. As the amount of revenue requirement found appropriate by the Commission decreases, the FEA also believes that the speed at which classes can be moved to EPMC based revenue allocation should increase.

f. CLECA/CSPG

CLECA/CSPG believe that customer classes such as large power should not and cannot continue to subsidize other customer classes. CLECA/CSPG urge the Commission to demonstrate our commitment to the goal of an EPMC revenue allocation by adopting a fixed implementation schedule in the general rate case. CLECA/CSPG support full implementation effective January 1, 1988.

CLECA/CSPG recognize that while favoring an immediate shift to EPMC revenue allocation, such may not be acceptable to the Commission especially in the event of an increase as proposed by Edison. If there is a phase-in, CLECA/CSPG recommend that it be adopted in only two phases -- January 1, 1988, and January 1, 1989. CLECA/CSPG believe that a longer phase-in will increase the danger of bypass by keeping large power rates at unnecessarily high levels for a longer period and reducing the credibility of the Commission's commitment to a full EPMC allocation.

CLECA/CSPG also favor a phase-in using a capped EPMC methodology. CLECA/CSPG state that Edison's blend of EPMC/SAPC undermines the commitment to EPMC allocation.

In CLECA/CSPG's view, however, in undertaking a phase-in there should not be any discretion or conditions precluding the attainment of full EPMC by a certain date, even potential rate shock. CLECA/CSPG therefore endorse either the FEA's or IU's phase-in proposals as providing the greatest certainty and appropriate price signals.

Finally, CLECA/CSPG see a danger in linking the phase-in of a full EPMC allocation to ARA cases especially in light of the potential for their elimination. (See D.87-05-071.) However, as long as the ARA continues, CLECA/CSPG state that the escalation factors developed in the ARA could be used in making adjustments to marginal demand and customer costs adopted in the general rate case without relitigating either these costs or the escalation factors. If the ARA ceases to exist, CLECA/CSPG suggest that the escalation factors would have to be adopted in ECAC.

g. <u>TURN</u>

While not addressing revenue allocation in an opening brief, TURN did so in its reply brief filed on August 24, 1987. TURN states that all parties recognize that the movement to full EPMC should be phased-in to avoid rate shock to the residential

class. TURN urges the Commission to encourage rate stability and avoid rate shock.

To this end, TURN specifically recommends the adoption of PSD's cap methodology. TURN believes that PSD's revenue allocation is also preferable to all other proposals because it reduces the incentive for large industrial users to seek special contracts and lessens those customers' ability to use the threat of bypass to obtain even greater concessions in future proceedings.

2. <u>Discussion</u>

We have carefully considered the proposals of each of the parties regarding the implementation of an EPMC revenue allocation for Edison. As in the case of the EPMC methodology itself, we note a striking unanimity in the positions which have been taken. Although CMA, IU, FEA, and CLECA/CSPG suggest that an immediate move be made to full EPMC revenue allocation, each has acknowledged the dramatic shift in revenue responsibility which such a change could cause and have suggested various approaches to mitigate that impact. Further, despite their recognition of the possible need to phase-in EPMC, these parties, however, also seek assurance from the Commission, in the form of a fixed schedule of implementation, that the Commission remains firmly committed to EPMC.

The differences between the parties center on the mechanism to be used for mitigating the effects of EPMC, the length of time which should be allowed to phase-in an EPMC revenue allocation, and the forum for implementing that phase-in. With respect to these issues, we again find similarities in the positions of the parties. Except for Edison, all of the other parties favor a capping approach which stays "true" to EPMC rather than an incorporation of SAPC in the phase-in process. The parties' positions also reflect endorsement of a phase-in that is no longer than three years and possibly as short as two years depending on the revenue requirement adopted for Edison in this proceeding. Finally, except for Edison, all other parties believe

that it is most appropriate for the phase-in to be implemented in ECAC, as opposed to the ARA (attrition) proceeding.

With these basic positions, we also agree. The need to mitigate the negative effects on certain customer groups caused by the shift to EPMC is even more pronounced for Edison than it was for PG&E. Additionally, unlike PG&E, Edison's current rates are not close to full EPMC, having not been allocated on that basis in the past, and will not be the subject of a significant rate decrease as a result of this proceeding. While we intend to match cost responsibility to the appropriate customer group, we do not intend to cause rate shock to those customer groups (e.g., domestic) who have no options in purchasing or generating electricity other than accepting service from the utility.

We also find that the classes (e.g., large power) who will ultimately benefit most from our adoption of EPMC are also those, as PSD has noted, who are able to make economic decisions, including consideration of revenue allocation adjustments, on a multi-year basis. We believe that our move to EPMC in this case will provide significant enough rate realignments and provide sufficient assurance of our commitment to EPMC that the large power class can properly assess whether bypass of the utility system is economically warranted.

We find that it is therefore reasonable to adopt a phase-in of the full EPMC revenue allocation for Edison. The method which we endorse is a phase-in approach with caps as necessary for individual classes. This approach will permit us to implement a full EPMC methodology while allowing us sufficient flexibility to take into account the need to mitigate any resulting rate shock.

In determining the most appropriate caps to adopt, we have developed the following table to reflect the impact various revenue allocation approaches would have on rates. This table, based for illustration purposes on a zero-dollar increase, includes revenue allocations (1) proposed in this proceeding, (2) adopted in PG&E, (3) based on full EPMC, (4) based on SAPC, and (5) based on a 5% cap for all classes.

11/18/87

SOUTHERN CALIFORNIA EDISON COMPANY
ALTERNATIVE REVENUE ALLOCATION METHODS

CUSTOMER GROUP	(1) SALES (GWH)	(2) PRESENT RATE REV (000's)	SAPC (000's)	(%) INC.	(3) FULL EPMC (000's)	(%) INC.	(SCE) 2/3 SAPC 1/3 EPMC (000's)	(%) INC.	(PSD) GENERAL CAPPED EPMC (000's)	(%) INC.	(PGE) SELECTIVE CAPPED EPMC (000's)	(%) INC.	(REVISED) ALTERNATE CAPPED EPMC (000's)	(%) INC.
DOMESTIC	19,832	1,610,007	1,610,007	0	1,921,571	19	1,713,862	6	1,738,742	8	1,690,466	5	1,690,466	5
SM/MED POWER														
GS-1	3,953	407,611	407,611	0	417,741	2	410,988	1	440,220	8	427,992	5	427,992	5
GS-2	17,846	1,569,264	1,569,264	0	1,472,767	(6)	1,537,098	(2)	1,551,201	(1)	1,583,211	1	1,581,270	1
LARGE POWER														
TOU-8:2ND	6,782	567,362	567,362	0	507,406	(11)	547,377	(4)	534,429	(6)	545,458	(4)	544,789	(4)
TOU-8:PRI	10,406	785,268	785,268	0	677,369	(14)	749,302	(5)	713,445	(9)	728,168	(7)	727,275	(7)
TOU-8:SUB	3,163	196,880	196,880	0	160,147	(19)	184,636	(6)	168,676	(14)	172,157	(13)	171,946	(13)
AGRICULTURE														
PA-1	1,723	144,241	144,241	0	141,961	(2)	143,481	(1)	149,522	4	147,847	2	151,453	5
PA-2	354	28,347	28,347	0	27,198	(4)	27,964	(1)	28,641	1	29,053	2	29,194	3
STREETLIGHTING	471	75,137	75,137	0	57,957	(23)	69,410	(8)	59,240	(21)	59,764	(20)	59,732	(21)
TOTAL	64,529	5,384,117	5,384,117		5,384,117		5,384,117		5,384,117		5,384,117		5,384,117	

REVENUE REQUIREMENT: 5,384,117

(1) September Update.
(2) Based on September Update Sales and Present Rates as of November 15, 1987.
(3) Based on Marginal Costs from this decision.

Based on the record in this proceeding, we find that a modification of Edison's approach is best matched to our goals. We will adopt an approach that moves each class 1/3 of the way to full EPMC, with a cap of 5% on increases to any class in the first year. Any remaining revenue decreases will be spread to the large power classes in proportion to the deviation of each class from full EPMC. We believe that our adoption of a 5% cap for residential provides adequate relief from rate shock while still providing significant rate reductions for large power customers. Large power customers will see a decrease of greater than 1/3 of the percentage difference between present rates and full EPMC. This faster approach to EPMC will assure large power customers of our commitment to expeditiously achieve full EPMC.

For subsequent years, we will continue phasing-in to full EPMC, mitigating rate shock as required by using caps. We ask the parties to provide such capping proposals, as necessary, on an annual basis, the nature of and forum for which are discussed below. We assure the parties that this finding in no way signals a retreat from EPMC. We intend to achieve full EPMC revenue allocation for Edison as soon as possible, and this intent should be reflected in any revenue allocation proposed for Edison in 1989 and 1990. We believe, however, that to achieve our goal of full EPMC and ensure rate stability the adopted revenue allocation for the two years following the test year should be based on the circumstances existing at that time.

With respect to the appropriate forum for making the necessary revenue allocation adjustments, we concur with PSD and the majority of the parties that the ECAC proceeding should be used. The initial reason for instituting the 3-R's rulemaking (R.86-10-001) was specifically to consider whether the continuation of the ARA (attrition) proceeding made sense in light of current and expected economic conditions. We found in D.87-05-071 that low inflation and more stable capital costs could lead to relatively small ARA increases over the next few years. Further, the elimination of ARA could foster greater productivity and cost-cutting on the part of the utility. In response to this situation, we considered the complete elimination of ARA. Based on utility concerns that not all growth in demand results in a net increase in revenues (i.e., as resulting from an increase in residential customers), however, we limited the elimination of ARA at this time to the large power class. (D.87-05-0971, at pp. 6-7.)

Our partial elimination of the ARA proceeding coupled with our belief in the benefits to be achieved by its total elimination suggest that this proceeding is not an appropriate forum to implement the three-year phase-in of the EPMC revenue allocation adopted in this proceeding. The uncertainty about the future of this proceeding, as well as its elimination for a significant class, makes the ARA proceeding inappropriate for a process which should take place expeditiously and must consider all class groups. Our decision to use the ECAC proceeding for consideration of revenue allocation issues also mirrors our conclusions in PG&E's most recent general rate case. (See D.86-08-083, at p. 52.)

With respect to the issues to be heard in ECAC, we share those parties' concerns regarding the complete relitigation of general rate case issues (i.e., marginal cost levels) in ECAC. We find our direction in PG&E's current ECAC proceeding regarding the presentation of revenue allocation and rate design issues in that proceeding to be dispositive. Specifically, in D.87-07-091, we concluded as follows:

> "Our past practice, with some exceptions, is that rate design, revenue allocation, and marginal cost issues should be reviewed in general rate cases and not in ECAC proceedings. However, there are circumstances that justify deviation from that practice here. Moreover, the decision in PG&E's last annual rate case stated that the Commission would allow for

changes in the caps on EPMC in future [ECAC] proceedings.

* * *

"Accordingly, to provide the Commission with reasonable flexibility, in addition to showings based on SAPC, the record in this phase should include showings based on EPMC for interclass allocations. However, in the interest of not allowing this proceeding to become bogged down in either major policy arguments or the minutia inherent in full-blow rate design proceedings, we will limit EPMC showings ... to adjustment of the caps applied to the EPMC interclass allocation previously adopted." (D.87-07-091, at p. 5.)

We therefore find that Edison's ECAC proceedings are the appropriate forums for considering inter-class revenue allocation and the phase-in and capping of the EPMC revenue allocation for the ECAC forecast period. As stated in D.87-07-091, the consideration of revenue allocation issues in ECAC, however, does not and should not include relitigation of the marginal cost structure and levels adopted in this proceeding.[30]

For rate changes occurring between this rate case and Edison's 1989 ECAC, the rate schedule changes should consider both the system average percentage change methodology and the phased-in EPMC methodology. Edison should file proposals using both methods and indicating the utility's preferred approach. Similarly, the revenue allocation approach proposed in Edison's ECAC proceedings for the 1989 and 1990 periods should identify the methodology to be applied to Edison's intervening offset filings made after each of these proceedings if other than SAPC.

30 We note that Edison and PSD have suggested some minor adjustments to customer and demand charges to reflect changes in the revenue requirement in the period between rate cases. These propriety of such adjustments are discussed in the rate design section of this decision. Our conclusions, however, will be in keeping with our findings above.

The only exception to this approach will be for minor rate adjustments. In those cases, for ease of administration, we will follow the approach adopted for PG&E in D.86-08-083 and permit Edison to use equal cents per kWh for rate adjustments less than 1%.

D. Inter-Class and Intra-Class Revenue Allocation

In D.86-08-083, the Commission adopted for PG&E an EPMC revenue allocation for both inter-class and intra-class revenue allocation. In this proceeding, the parties' attention largely focused on the inter-class revenue allocation. For intra-class revenue allocation, however, Edison made a separate proposal for small and large light and power customers, and PSD attempted to develop an intra-class revenue allocation for agricultural and pumping customers.

Specifically, for those rate schedules within a rate group for which marginal costs have not been determined in this proceeding (i.e., GS-1, GS-1-APS, GS-1-PG, and TC-1), Edison recommends that the revenue requirement be allocated to rate schedule based on equal percent of present rate revenues.[31] For those rate schedules for which marginal costs have been calculated in this proceeding (i.e., Proposed Schedules TOU-8-SEC, TOU-8-PRI, and TOU-8-SUB), Edison proposes to further allocate the revenue requirement for the customer group to those rate schedules on the basis of full EPMC.

Edison notes that there was no disagreement concerning its proposal and asks that it therefore be adopted. In its brief, CLECA/CSPG has indicated its agreement with Edison that allocation

31 For example, once the GS-1 Rate Group revenue requirement is determined based upon EPMC, that revenue requirement should be allocated to the rate schedules in that rate group on an equal percent of present rate revenues basis.

to service voltage sub-classes within the large power classes should be made on a full EPMC basis.

For agricultural and pumping customers, PSD had supported an intra-class revenue allocation for PA-1 and PA-2 and PSD's proposed optional agricultural schedules based on specific customer-incurred costs and use characteristics. As PSD has noted in it brief, the complexity of this effort and the absence of sufficient data, however, prevented PSD from establishing the level of refinement which it sought within the hearing time available. PSD therefore concludes that such a revenue allocation for the agricultural class cannot be undertaken at this time. PSD recommends, however, that Edison be ordered to collect the necessary data on agricultural customers to permit an intra-class revenue allocation for all agricultural rate schedules and options to be accomplished no later than the next general rate case.

We find that Edison's proposal for small light and power intra-class revenue allocation is reasonable in this particular case. Having no marginal costs calculated for rate schedules within the small light and power group, it would be futile to order an intra-class revenue allocation based on EPMC. An allocation based on equal percent of present rate revenues is therefore an appropriate alternative in this context and should be adopted. The only exception to this finding is for Schedules TOU-GS and GS-2 for which the revenue allocation should be determined by applying the adopted rates to the billing determinants proposed for those schedules by both Edison and PSD.

We also find, as PSD has concluded, that our record is insufficient to order a cost-based intra-class revenue allocation for the agricultural rate schedules in this proceeding. We will therefore adopt PSD's proposal, to which Edison has concurred, to allocate any revenue shortfall resulting from the implementation of new agricultural rate options equally among all agricultural rate schedules.

To the extent possible, however, it is our goal to achieve EPMC for all class revenue allocations. To this end, we will adopt the EPMC revenue allocation to rate schedule for the large power class. Further, we will direct Edison to collect the data to develop the marginal costs necessary to achieve an EPMC intra-class revenue allocation for the small light and power and agricultural rate schedules for Edison's next general rate case. With such information in the record of that proceeding, an EPMC revenue allocation can be achieved for both inter-class and intra-class revenue allocation at that time.

E. Street and Area Lighting

The costs imposed on the utility system by streetlight customers fall into two basic categories: a facilities component and an energy component. Traditionally, the revenue requirement for the streetlight group had been excluded from the marginal cost revenue allocation process. In Edison's last general rate case (D.84-12-048), for instance, the Commission had found that the unique combination of operating charcteristics of the streetlight group required their exclusion from the revenue allocation process. These characteristics included non-metered service, uniform load shape, utility ownership of the end-use equipment or facilities (streetlights), and low, off-peak energy consumption.

In D.86-08-083, in which we determined PG&E's marginal costs for 1987, the Commission departed from this traditional approach. Specifically, the Commission determined that the energy component of streetlight costs should be included in the revenue allocation process while the facilities charges would continue to be excluded.[32] In doing so, we recognized the uniqueness of the

32 We also found that the exclusion of streetlight facilities would also permit us to unbundle that component of streetlight rates and determine its revenue requirement independently.

streetlight facility being associated with end-use, but the similarity between streetlight energy charges and energy charges incurred by other customer classes. We determined that, in order to treat all classes equally, the revenue requirement associated with streetlight energy usage should be included in the marginal cost revenue allocation.

Despite this finding, Edison and Cal-SLA maintain in this proceeding that the streetlight group should continue to be excluded in its entirety from our marginal cost revenue allocation. Cal-SLA and Edison both point to the small amount of energy usage by streetlights compared with the energy consumption of other classes. Cal-SLA states that this usage does not justify adopting "the fragmented method" (Cal-SLA Brief, at p. 5) used in PG&E for streetlight revenue allocation. Cal-SLA argues that such an approach furthers no analytical purpose and that exclusion of the energy component from revenue allocation creates no serious revenue shortfall.

Edison similarly relies upon the unique characteristics of streetlights as a basis for continuing their complete exclusion from revenue allocation. Edison disagrees, however, with Cal-SLA that no serious revenue shortfall will result from such an approach. Edison states that simple logic dictates that if streetlight customers are excluded from the usual revenue allocation process, revenues must then be allocated in some other fashion. In Edison's view, the selection of an alternative method can indeed cause a serious revenue shortfall within the customer group.

PSD urges the Commission to follow its approach used in D.86-08-083. PSD notes that the very purpose of establishing customer classes is to group together customers that have similar characteristics, but are distinct in their characteristics from other groups. Thus, while PSD acknowledges that the streetlight group might have a small amount of level, off-peak energy usage relative to total consumption, this circumstance, according to PSD, does not justify the exclusion of the group in its entirety from the allocation of those revenues required to meet energy needs.

PSD notes, however, that the logic of including streetlight energy charges in the revenue allocation process does not extend to inclusion of the facilities charges in that process. PSD states that facilities charges, unlike streetlight energy charges, bear no relation to the production, transmission, or distribution of electricity and therefore have no relation to a marginal cost revenue allocation.

We find that PSD has correctly interpreted and applied our most recent policy regarding the treatment of streetlight customers in the revenue allocation process. We believe that D.86-08-083 makes clear our decision to exclude only the streetlight facilities charge from this process. As that decision reflects and PSD has indicated, this exclusion is appropriate for a charge which is related to end-use and which is not related to these components which are included in a marginal cost revenue allocation. Despite the low, off-peak energy usage by streetlight customers, it is energy consumption nonetheless and as such is properly included in determining class revenue responsibility. We therefore find reasonable and adopt the continued exclusion of streetlight facilities from the revenue allocation process, but the inclusion in that process of streetlight energy charges.

F. Contract Rate Revenue Deficiencies for Incremental Sales

As we discuss in the Rate Design section of this decision, Edison has proposed two contract rate schedules as a means of mitigating uneconomic bypass. Edison has proposed to allocate the estimated contract rate revenue deficiency of $20 million resulting from one of these rate schedules (TOU-8-CR-1) back to all customer groups and rate schedules on an equal cents per kWh basis.

We have concluded in our section on rate design that the generic special contract rate schedule being proposed by Edison (TOU-8-CR-2) should not be adopted at this time and that issues related to the development of that schedule are properly deferred to the 3-Rs Rulemaking (R.87-10-001). D.87-05-071 in the 3-Rs Rulemaking makes clear that the the policies adopted in that decision are to be implemented in the 3-Rs Rulemaking through the examination and development of guidelines for special contracts, rate options and rate unbundling for different customer classes, and revised forecasts of sales and revenues.

We will permit Edison to implement the TOU-8-CR-1 schedule at this time, but will defer any revenue allocation issues to R.87-10-001 as well. It is therefore unnecessary for any forecasted contract rate revenue deficiency to be allocated to Edison's customers at this time. We find that while revenue deficiencies are appropriately considered in the revenue allocation process, an estimate of losses which may be incurred to avoid a potential bypass problem is presently too speculative to warrant its adoption at this time. We believe that any issues related to the manner in which this revenue deficiency is to be determined and allocated should first be considered in the same proceeding, R.87-05-071, in which the guidelines for special contracts and contract rates are being developed.

G. Adopted Revenue Allocation

The adopted revenue allocation shown on the following table of this decision is based on the total revenue requirement adopted for Edison as of January 1, 1988. This adopted revenue requirement includes revenue changes resulting not only from the decision in this general rate case, but also decisions relating to nuclear decommissioning (OII 86), the SONGS 2 and 3 pre-commercial operation date and post-commercial operation date revenue requirement, amortization of various deferred debit accounts, and refunds for 1987 impacts of the Tax Reform Act of 1986. Present rate revenues reflect the November 1987 rate changes resulting from decisions in Edison's ECAC, AER, ERAM, CLMAC, and Chevron settlement and Uranium contract termination proceedings. (See Appendix E and Appendix F for revenue detail.) The adopted ECAC and AER revenues shown in Appendix E include adjustment for fuel savings due to operation of the Balsam Meadow hydroelectric generating plant. Appendix E shows no revenue change because by coincidence the fuel savings decrease is exactly offset by increases due to adopted changes in franchise fee and uncollectible factors.

SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED PHASE-IN SCALED REVENUE ALLOCATION 1\
EFFECTIVE JANUARY 1, 1988

CUSTOMER GROUP	SALES 2/ (GWH)	PRESENT RATE REV (000's)	TOTAL MC REVS 3/ (000's)	FULL EPMC (000's)	(%) INC.	PHASE-IN SCALED (000's)	(%) INC.	AVERAGE RATE
DOMESTIC	19,832	1,610,007	1,584,484	1,909,515	18.60	1,689,171	4.92	0.085
SM/MED POWER								
GS-1	3,953	407,611	344,607	415,238	1.87	410,153	0.62	0.104
GS-2	17,846	1,569,264	1,214,887	1,463,922	(6.71)	1,534,150	(2.24)	0.086
LARGE POWER								
TOU-8:2ND	6,782	567,362	418,574	504,365	(11.10)	546,088	(3.75)	0.081
TOU-8:PRI	10,406	785,268	558,782	673,311	(14.26)	747,596	(4.80)	0.072
TOU-8:SUB	3,163	196,880	132,110	159,188	(19.14)	183,841	(6.62)	0.058
AGRICULTURE	2,077	172,588	139,455	168,103	(2.60)	171,093	(0.87)	0.082
STREETLIGHTING	471	75,137	19,882	57,812	(23.06)	69,362	(7.69)	0.147
TOTAL REVENUE REQUIREMENT	64,529	5,384,117	4,412,782	5,351,454		5,351,454		0.083

1/ Although facilities charges and optional TOU meter charges have been excluded from the revenue allocation process, these amounts have been added to the figures in this table in order to obtain the correct percentage increases and average rate calculations. A breakdown of facilities charges by customer group is given in Appendix F.

2/ Sales figures are taken from the September Update and reflect sales that have not been adjusted for employee discounts.

3/ Based on Marginal Costs from Exhibit 41 as modified by this decision.

XI. Rate Design

A. Introduction and General Policy Considerations

In the preceding section, we determined how Edison's adopted revenue requirement would be allocated to customer group and to rate groups within those customer groups (i.e., domestic, small and medium power (GS-1 and GS-2), large power (TOU-8 (Sec), TOU-8 (Prim), and TOU-8 (Subtrans)), agricultural and pumping (PA-1 and PA-2), street and area lighting). We now turn to our final task in this general rate case of determining the specific terms, conditions, and charges under each of Edison's rate schedule included within each customer and rate group.

As in the case of adopting a revenue allocation based on Equal Percent of Marginal Cost (EPMC), our goal in rate design is to achieve rates which reflect the costs which the customer imposes on the system. This approach not only results in an equitable distribution of Edison's revenue requirement, but also provides the most accurate price signals to the customer regarding his energy consumption. To achieve these goals, we must also ensure that rates are structured in a way so that customers can understand and respond appropriately to those signals.

For reasons which similarly supported our phase-in of an EPMC revenue allocation for Edison, however, we also recognize that full implementation of marginal cost-based rates may result in severe bill impacts for some customers. For PG&E, for instance, we recently found it necessary to temporarily limit the impact of certain charges to certain rate groups by imposing rate "limiters" or "caps." In adopting these rate limiters, we sought, however, to still ensure recovery of the revenues allocated to the affected customer group or class and to provide customers whose rates were capped with a clear signal of future bill increases. (D.86-12-091, at pp. 57-59.)

In D.87-05-071 in the 3-Rs Rulemaking, we have also considered the impact of rate design and special contracts on bypass, the situation in which the customer chooses self-generation over utility service discussed at length in prior sections. Among the policies adopted in D.87-05-071 in the 3-Rs Rulemaking (R.86-10-001) to address the threat of uneconomic bypass was the need for the utility to offer special contracts and rate options to customers in the large power class. We have made clear in D.87-05-071 our intention to consider in the 3-Rs proceeding the guidelines and terms of the special contracts and rate options referenced in that decision along with new forecasts of sales and revenues for the large power class which take into account the regulatory revisions adopted in D.87-05-071.

The rate design principles which are to guide the development of the rate options to be considered in the 3-Rs Rulemaking, however, are also appropriately considered in the rate structures adopted in this proceeding. These principles include the need to "unbundle" rates (the process of pricing each of the various utility services separately) and to differentiate between services and price. This approach, which, as an example, would include the recovery of fixed costs in fixed charge components, offer another means of providing customers with accurate price signals.

Our current rate design philosophy can therefore be summarized as an effort to achieve easily understood, cost-based rates which are designed to recover the customer groups' revenue requirement; to include any terms or conditions necessary to mitigate, to the extent possible and practical, any negative bill impacts; and to reflect a customer's usage patterns and characteristics. This philosophy has largely been mirrored in the rate design recommendations provided in this proceeding not only by Edison and PSD, but by numerous interested parties. These parties include Toward Utility Rate Normalization (TURN), the Western

Mobilehome Association (WMA), recreational vehicle (RV) park owners, the Schools Committee to Reduce Utility Bills (SCRUB), the California Large Energy Consumers Association and the California Steel Producers Group (CLECA/CSPG), the Federal Executive Agencies (FEA), the Industrial Users (IU), the California Manufacturers Association (CMA), the State Department of General Services (DGS), the Cogenerators of Southern California (CSC), the Association of California Water Agencies (ACWA), and the California City-County Street Light Association (CAL-SLA).

Before proceeding to those specific recommendations, we note, for Edison's benefit, that we appreciate the differences in operations and customers between Edison and PG&E. Edison has asserted this fact as a reason why the rate design approved for PG&E may not be suitable for Edison. Our reliance on decisions relating to PG&E's adopted rate design is, however, appropriate as a means of identifying current Commission rate design policy; determining whether that policy is to be continued, modified, or abandoned; and ensuring, to the extent possible, consistent treatment of all ratepayers.

Finally, Edison and PSD urge that the Commission recognize in reviewing their recommendations that their jointly and separate proposed rate structures were based on the assumption that ERAM would continue through the test year 1988. Because the Commission has recently eliminated ERAM for large light and power customers in D.87-05-071, Edison wishes to reserve the right to make needed modifications, if any, to its rate design through the further proceeding provided by D.87-05-071 in R.86-10-001. Our review of that decision above makes clear that the Commission does intend to review in R.86-10-001 rate options and special contracts offered to the large power group. To the extent provided by that rulemaking, Edison and PSD are, of course, entitled to participate and make rate design recommendations.

B. Domestic Customer Group

In this proceeding, Edison and PSD reached agreement on almost all of the components of the rate design for the domestic customer group. Issues, however, remain for these two parties with respect to the development of the optional time-of-use rate schedule (TOU-D) and the appropriate submetering discount to be applied to the master-meter schedules for mobilehome parks (DMS-2).

TURN, WMA, and the RV park owners also presented positions on several issues related to residential rate design. TURN focused on Edison's and PSD's recommendation to eliminate the minimum bill, while WMA and the RV park owners addressed the discount and charges provided under the DMS-2 schedule and the applicability of that schedule or a new, similar schedule to RV park owners.

1. Baseline

Edison and PSD are in agreement on the quantities to allow for baseline. Specifically, Edison and PSD have agreed that for all customers, except all-electric customers and residents in Zone 15 of the CEC's climatic regions, baseline allowances should be set at the mid-point of the range allowed by Public Utilities Code section 739 (55 percent of average aggregate use). For all-electric customers other than those residing in Zone 15, the parties have agreed that the baseline allowance should be set at the maximum allowed under the statutory range (60 percent of average aggregate usage for summer and 70 percent of average aggregate usage for winter). Edison and PSD also agree that all usage at and below the baseline allocation should be priced at 85 percent of the system average rate, the maximum charge allowed by law. (Cal.Pub.Util. Code, Section 739).

For Zone 15, the high desert area of the Coachella Valley, Edison and PSD have agreed to an adjustment of the seasonal allocation of the baseline allowances similar to that adopted in Edison's last general rate case (D.84-12-068). In that case, the

Commission had determined that the total annual baseline allowance for Zone 15 should be no more than that established under the normal formula. However, the Commission concluded that the allocation of that allowance to season should be modified to allow a greater allowance during the summer months when the Zone 15 area experiences extreme heat. (D. 84-12-068, at pp. 292-296.) As of June 1987, this allowance was 1,200 kWh per month for the summer.

In this proceeding, Edison had orginally proposed that baseline quantities for customers residing in Zone 15 be established under the same methodology as that applied to the other CEC zones. Subsequent to making this proposal, however, Edison was asked by the Coachella Valley Association of Governments (CVAG) to reconsider its position and provide baseline quantities for Zone 15 based on the Commission's methodology adopted in Edison's last general rate case. In response to that request, Edison proposed a summer baseline quantity of 1,200 kWh per month with the winter baseline quantities set such that the total annual baseline allowance for Zone 15 would be the same as Edison had originally proposed. This proposal, with which PSD agreed, is considered by both parties not to have a material impact on customers outside of Zone 15.

Edison and PSD also agree that for master-metered Schedules DMS-1 and DMS-2 (applicable to submetered multifamily and mobilehome domestic customers) the baseline quantities should be the same as for other domestic and comparable non-master-metered customers. Edison and PSD also agree that baseline quantities for Schedule DM, master-metered multifamily domestic customers without submetering, should be reduced in proportion to the lower average use of customers on this schedule.

We find that Edison and PSD have applied the appropriate methodologies in calculating the baseline allowances for all zones and for all domestic rate schedules. We also find reasonable the allocation adjustment for Zone 15 customers in recognition of the

extreme heat in that region during the summer and the absence of any material impact on other customers. These baseline quantities for Zone 15 should also be based on the 4-month summer/8-month winter periods adopted for this zone in Edison's last general rate case. (D.84-12-068, at p. 296.) We therefore find that the following daily baseline quantities are reasonable for Schedules D, DMS-1, DMS-2, DAPS-2, DE, and D-PG, and should be adopted with implementation effective as of the next seasonal change. The baseline quantities, adopted for the DM schedule are included in an appendix to this decision.

Baseline Allowances
Schedule Nos. D, DMS-1, DMS-2, DAPS-2, DE, and D-PG

Monthly Baseline kWh Allowances:

Line No.	Baseline Region (1)	Summer Basic (2)	Summer All-Electric (3)	Winter Basic (4)	Winter All-Electric (5)
1.	10	252	302	259	493
2.	13	441	800	321	1,072
3.	14	363	532	292	855
4.	15	1,200	1,200	330	670
5.	16	250	445	279	1,035
6.	17	333	425	278	615

Adopted Daily Baseline kWh Allowances:

Line No.	Baseline Region (1)	Summer Basic (2)	Summer All-Electric (3)	Winter Basic (4)	Winter All-Electric (5)
1.	10	8.2	9.8	8.6	16.3
2.	13	14.4	26.1	10.6	35.5
3.	14	11.8	17.3	9.7	28.3
4.	15	39.3	39.3	10.9	22.1
5.	16	8.2	14.5	9.2	34.3
6.	17	10.9	13.9	9.2	20.4

2. Domestic Time-of-Use

Edison proposes two new schedules for the domestic customer group: a seasonal option (Schedule DS) and a time of use option (Schedule TOU-D). Edison states that it has proposed these

options to help mitigate the negative impacts on domestic customers of increased rates and changed allocation procedures and to provide these customers with more control over their electric bills.

For its proposed optional Schedule TOU-D, Edison established a ten cents-per-kilowatt-hour premium for incremental summer on-peak energy and a five cents-per-kilowatt-hour discount for incremental off-peak energy. For the seasonal Schedule DS, Edison similarly charges a premium on all summer month kilowatt-hours in excess of average winter month usage and a discount on winter month kilowatt-hours in excess of average summer month usage.

PSD also recommends the use of rate options for the domestic customer group. PSD accepts Edison's proposed seasonal option, Schedule DS. Additionally, the two parties have reached an agreement to open the optional time-of-use program to all customers, but with a limit of 10,000 new meters per year. The parties have similarly agreed that Edison should target the marketing of the program primarily to its largest customers. Edison and PSD also concur that the seasonal option should be limited to customers with an established billing history of one year and an average monthly usage in excess of 1,200 kWh seasonal option (Schedule DS). The parties agree that the expected revenue shortfall, which both parties find will have no significant impact on the nonparticipant, should be included in the domestic customer group revenue requirement.

PSD differs with Edison, however, on the rate structure which should be adopted for the optional TOU schedule. In contrast to Edison's "premium/discount" approach, PSD recommends a conventional TOU rate structure requiring a three-tiered rate structure with all three time differentiated charges based on marginal costs. PSD also recommends that a floor be established for the TOU-D bill equal to the customer's usage times the off-peak energy rate. According to PSD, this approach is necessary to

eliminate the possibility, even though unlikely, that a customer could have a negative bill resulting from the interaction of exclusively off-peak usage and baseline allowances.

The positions of Edison and PSD regarding the appropriate rate structure for the optional TOU-D rate schedule are summarized below. Our resolution of this issue and our findings on the DS proposal and the proposed limitations on both rate options follow that summary.

a. <u>TOU-D Rate Schedule</u>

According to Edison, its seasonal and TOU options for residential customers are designed to complement each other. Edison states that the seasonal option provides those customers who have low summer season usage a reduced rate without the need for a time-of-use meter. The TOU option, according to Edison, is directed to customers who can shift their daily usage to the off-peak period and will benefit from a time-of-use meter. Edison believes that the complementary nature of these two options depends on the premium/discount feature as a common link to permit customers to understand and compare the two options. Edison asserts that by using the premium/discount approach, the customer can readily assess the cost of using energy in the on-peak period and the savings to be realized by shifting use to the off-peak period.

Edison believes that the simplicity and ease of comprehension achieved by its rate option proposals is critical. According to Edison, while its TOU-D option may be chosen by only one out of ten customers, Edison believes that it is obligated to clearly communicate the options to all qualifying customers to permit them to make an informed decision.

With respect to the rate established by Edison for the TOU-D schedule, Edison states that an optional rate must be set below average cost in order to be desirable. The level below average cost, according to Edison, is a matter of judgment based on

weighing the need to attract the customer against the need to mitigate the amount of revenue shortfall. With these principles in mind, Edison established its optional rates approximately halfway between average and marginal costs. Edison states that under this rate structure the customer receives approximately half the difference between the average and marginal cost in the off-peak period in the form of a discount and pays approximately half the difference in the form of a premium in the summer on-peak period.

Edison believes that PSD's proposed three-tier TOU-D rate is unduly complicated and will not achieve the goal of attracting customers. Edison states that PSD has placed too much emphasis on the need to mirror marginal cost in the rate design and too little concern on the need for simplicity of design and comprehension by the customer.

PSD characterizes the dispute between itself and Edison over the appropriate rate structure for the optional TOU-D schedule as a contrast between short term simplicity and long term accuracy. PSD notes that the basis for the Edison proposal is to provide a simple way for the average residential customer to readily compute the costs they incur by using on- and off-peak energy, irrespective of what the base charge may be. PSD asserts, however, that Edison has acknowledged that the similarity of Edison's proposed rates to marginal cost-based rates is merely a coincidence.

PSD asserts that its proposed TOU-D rate structure is preferable to Edison's since it can not only be understood by customers, but also provides more accurate price signals with rates based on time-differentiated marginal costs. PSD believes that any customer signing up for a TOU schedule understands that he will pay more for on-peak usage and less for off-peak usage, a differential which will be seen in a simple review of his bill. In PSD's opinion, the Edison approach will only make for simpler computation if the customer knows his instantaneous usage.

PSD states that Edison has not made clear what steps it would take when the recommended discounts become further estranged from marginal cost relationships. PSD asserts that the proper function of TOU rates is to reflect costs imposed on the system, a goal achieved, according to PSD, only by PSD's recommended TOU-D structure.

b. Adopted Schedules

If the goal of offering optional rates to residential customers is to permit these customers to understand the impact of their energy usage and to control that usage, we believe that such a goal can only be achieved by offering the most accurate price signals. As we have stated repeatedly in this decision, these signals result from relying on marginal cost-based rates.

We have also endorsed, however, the need to achieve simplicity in rate design in order to enhance the customer's understanding of his bill. This goal, as Edison has recognized, is particularly important in developing a new rate option and attracting customers to the schedule.

We do not believe, however, in this case, that the goal of simplicity in rate design outweighs the need for cost-based rates. For an option schedule aimed at providing the customer with truly cost-based rates, the primary emphasis should be on the relation of the charge to the cost imposed by the customer on the system.

We find that PSD's proposed three-tier rate design achieves the goal of cost-based rates for the TOU-D schedule. We further agree with PSD that its approach is not so overly complicated that the customer will not be able to understand the changes in his consumption patterns which will be required to lower his bill. We also share PSD's concern that in the future the differential between Edison's marginal costs and its proposed discount, which is not significant at this time, might increase and

thereby move the proposed rates further from marginal costs and the very purpose of the schedule.

We therefore find that PSD's proposed TOU-D schedule is reasonable and should be adopted in this proceeding. The estimated revenue deficiency from TOU-D should be allocated to all residential customers. We note that the TOU-D schedule is designed as an option. Should Edison encounter significant difficulties in communicating the availability of the TOU-D schedule or its impact, Edison can use that experience as a basis for offering a different rate structure in its next general rate case. Due to the complexities of the schedule, Edison should, however, have a reasonable period of time to implement the new schedule, but should offer the tariff no later than June 1, 1988.

We also find reasonable the DS schedule and the limitations placed on the availability of the DS and TOU-D schedule to which Edison and PSD have agreed. The adoption of these recommendations and both optional schedules will provide to an appropriate level of residential customers significant options for controlling their energy usage and reducing their electric bills.

3. <u>Minimum Bill and Customer Charges</u>

Under Edison's current domestic rate schedule, Edison provides for a minimum bill under which customers pay a certain amount each month even if their usage is less than that represented by the minimum bill. In this proceeding, Edison and PSD have recommended that the existing minimum bill or charge, which accrues on a daily basis, be replaced by a customer charge of 15 cents per day or $4.65 a month. This proposal was opposed by TURN.

a. <u>Parties Positions</u>

In this proceeding, Edison and PSD have agreed that the existing minimum charge should be replaced by a daily customer charge. According to Edison and PSD, the charge will reflect in rates administrative costs associated with reading the meter and billing the account and a portion of the fixed distribution costs associated with providing service to the customer. The parties believe that this charge is therefore consistent with the process of unbundling rates and sending clearer price signals.

Edison and PSD agree that the customer charge should be $4.65 per month based on a daily charge of 15 cents, less than a one cent difference from the figure derived by PSD based on marginal customer costs. The parties further agree that the proposed customer charge revenue should be deducted from the baseline revenue requirement when determining the baseline rate.

Both parties also agree that the function of the customer charge is to reflect marginal customer costs. While the proposed customer charge collects only a portion of Edison's marginal customer costs, Edison and PSD assert that their proposed customer charge will still achieve the objective of recovering a larger portion of fixed costs through the fixed component of the rate.

PSD acknowledges that some ratepayers may experience bill increases, but that this result is not solely from the imposition of a customer charge. Rather, PSD states that such increases result in the significant increase in revenue requirement responsibility of the domestic class due to the inclusion of marginal customer costs in revenue allocation and the move toward an EPMC revenue allocation for Edison.

TURN opposes replacing the current minimum bill with a customer charge. TURN states that under a minimum bill consumers pay a certain minimum amount even if their usage is so low that they would otherwise be billed less than the minimum amount. In contrast, according to TURN, a customer charge is a charge paid by all consumers in addition to the amount they are billed for the electricity they use. TURN notes that most consumers are not directly affected by the minimum bill because they use more than the minimum bill amount.

TURN states that similar proposals to replace the minimum bill with a customer charge have been rejected in recent SDG&E and PG&E rate proceedings. TURN notes that in both cases the

Commission refused to adopt customer charges for reasons of fairness and economic efficiency. (Citing, D.85-12-068, at p. 97; D.86-12-091, at pp. 25-26.)

TURN believes that this same reasoning is applicable to this proceeding. TURN asserts that the application of the customer charge results in penalizing customers living in certain regions and overcharging small users and that the charge itself is improperly based on the cost of connecting new customers. The totality of the effect of imposing the customer charge, in TURN's opinion, is therefore to create inefficiencies and waste in energy consumption by sending the wrong price signals to customers encouraging greater consumption and consumption in summer periods.

TURN further argues that almost 74% of Edison's residential customers would receive increased rates solely from the imposition of a customer charge. TURN states that the customer charge also improperly results in the greatest rate increase to customers in temperate zones who generally impose lower costs on the system. TURN further asserts that PSD's testimony demonstrated that the smallest users, many of whom are low-income, will receive the largest percentage increase from the proposed customer charge. According to TURN, Edison and PSD have inappropriately based customer charges on incremental customer costs when decremental customer costs more closely reflect the actual customer cost imposed on the system.

b. Discussion

In our decision adopting the rate design for PG&E's most recent test year (D.86-12-091), we supported in principle PSD's recommendation to establish a customer charge for residential customers. However, because of the constraints which baseline placed on the establishment of Tier I and Tier II rates, we found that a customer charge would distort these rates, thus obscuring its intended purpose. The customer charge was therefore rejected in favor of a minimum charge which was found to allow residential customers to pay a share of fixed costs and to better understand their rates. The minimum charge was adopted for both domestic TOU and domestic non-TOU customers. (D.86-12-091, at pp. 25-26, 30.)

In this proceeding, we similarly find supportable the principle of the customer charge. We agree with Edison's and PSD's reasoning that such a charge, based on marginal customer costs, would provide more accurate price signals to the domestic customer class regarding their usage.

We must, however, also consider the impact of such a proposal on all domestic customers. PSD has recognized that the Edison customer, following this proceeding, must face increased revenue responsibility related to the combined impact of the inclusion of marginal customer costs in the revenue allocation process and the move toward an EPMC inter-class revenue allocation. The impact of these changes on residential customers seems significant enough without a change in rate structure which will shift fixed charges into a single component. TURN has demonstrated that the effect of this change would be to impose a disproportionate increase on the smallest users.

As in the PG&E case, we are also concerned with the interaction of the customer charge with baseline rates. As shown by TURN, this interaction would result in increasing rates to certain temperate zone customers disproportionate with the costs which they impose on Edison's system.

Finally, as our section in this decision on marginal customer costs reflect, we have found that PSD's methodology for calculating those costs failed to take into consideration decremental customer costs. We adopted PSD's approach at this time, with certain modifications, only as a proxy for the approved incremental/decremental approach. While the customer charge is appropriately based on marginal customer costs, we share TURN's concern that the estimate used by PSD failed to take into consideration decremental customer costs which should have been part of that calculation.

For these reasons, we adopt TURN's recommendation and continue the minimum base rate charge at $0.10/day. PSD and Edison may renew their request in Edison's next general rate case at which time the calculations of marginal customer costs should be based on the proper methodology and our move to EPMC revenue allocation should be completed. These changes could be significant factors in determining the propriety of adopting a customer charge at that time.

4. DM, DMS-1, and DMS-2 Schedules

Under master-metered Schedules DMS-1 and DMS-2, Edison provides a monthly discount to multifamily accommodations and to mobilehome park owners who provide submetering service to their tenants. The discount mobilehome park owners are provided under the DMS-2 schedule stems from the statutory requirement (Public Utilities Code Section 739.5) that each utility provide a sufficient differential in the rate charged to mobilehome park owners to allow recovery of the reasonable average cost to such customer for providing a submetered service to individual mobilehome residents. The DMS-2 schedule also includes baseline allowances, which along with the submetered discount, were developed by the Commission after extensive hearings in Case Nos. 9988 and 10273 pursuant to Sections 739 and 739.5 of the Public Utilities Code. The present discount under the DMS-2 schedule is $.23 per space per day which equals $6.90 per space per month.

At issue in this proceeding is not only the calculation of the DMS-2 discount, but the need to adjust that discount to recognize a diversity benefit and the applicability of the DMS-2 schedule itself or the creation of a new, similar schedule for RV park owners. These issues have been the focus of the testimony and briefs of Edison, WMA, and the RV park owners. Edison's recommended discount for DMS-1 and the diversity factors to be applied to that discount and to charges under Schedule DM were not opposed by any party.

With respect to the calculation of the DMS-2 discount, following the filing of WMA's prepared testimony, Edison acceded to several of WMA's recommended changes to Edison's calculation and increased its originally recommended discount of approximately $5.10 per space per month to $6.88 per space per month. Edison did not concur, however, with WMA's proposed allowance for distribution energy losses nor the need to use a levelized fixed charge rate in that calculation. WMA's proposed discount, which includes an allowance for distribution energy losses of $2.94 per space per month, yields a total recommended discount of $10.76 per space per month.

PSD's recommended discount was similar to that originally proposed by Edison. Specifically, PSD had found, based on Edison's original cost study, that submetering costs were $5.14 per month. PSD's recommended discount, however, was $.64 per month due to the inclusion in its calculation of a deduction for the customer charge of $4.36 per month. Such an adjustment of the submetered discount, however, is no longer necessary given our rejection of PSD's and Edison's proposal to initiate customer charges for the domestic customer group.

The need to adjust the discount to recognize a diversity benefit was first recognized by the Commission in our consideration of PG&E's rate design for its most recent test year. In D.86-12-091 in that proceeding, we found that a diversity benefit existed when a master metered customer had more sales billed at baseline rates and less at nonbaseline rates than were actually used by his submetered customers. While PG&E and WMA disagreed in that case regarding the use of diversity factors and the method of their calculation, we concluded that an adjustment of the discount was required to correct an inequity in the billing of submetered mobile homes. For this reason, we adopted PG&E's diversity factors "as the best available quantification of diversity benefits." (D.86-12-091, at p. 35.) In response to WMA's concerns regarding the accuracy of PG&E's diversity factors, however, we directed PG&E in the future to base its diversity factors on the usage patterns of mobilehome parks individually metered by PG&E. (Id.)

In this proceeding, Edison did not initially recommend a diversity adjustment of the DMS-2 discount. Only after Edison had submitted its cost study supporting its discount and interested party testimony had been filed did Edison determine that such an adjustment was appropriate not only for the DMS-2 schedule, but also for the DMS-1 and DM schedules. Because of WMA's objection to the lateness of this proposal, the presiding ALJ, with the concurrence of the parties, concluded that hearings on this issue would be deferred to September, 1987, with prepared testimony being filed in advance of that date. On September 22, 1987, testimony was presented by Edison and WMA with concurrent briefs filed on this issue on September 30, 1987. PSD offered no testimony on this issue and did not propose a discount adjusted to reflect a diversity benefit.

a. Allowance for Distribution Energy Losses

For PG&E's most recent test year, WMA had recommended that line losses from the master meter to the submeter be considered in calculating the master meter discount. While we agreed in principle with WMA, we did not adopt WMA's line loss estimate since it was based on PG&E's entire distribution system and might not be applicable to mobilehome parks. We also found that WMA's approach was further flawed by the failure to consider the amount of distribution wire required to serve the typical submetered customer and by the estimate increasing the existing discount by nearly 40%. We directed PG&E, however, to conduct a study with WMA to determine the actual line losses of submetered mobilehome parks and to present the results of that study in PG&E's next general rate case proceeding. (D.86-12-091, at pp. 36-37.)

In this proceeding, WMA again seeks to include an allowance for distribution energy losses. WMA asserts that Edison's 1987 cost study of electric service in mobilehome parks is flawed for its failure to account for these losses which WMA states that even Edison admits do occur within mobilehome parks. WMA testified that an appropriate loss percentage was 8.02% which is based on an analysis of Edison's losses from the primary distribution level to the residential distribution system. Based on this figure, WMA calculated the cost of losses at an average of $2.94 per space per month, an amount which was added to WMA's initially calculated discount of $7.82 per space per month to yield the total recommended discount of $10.76 per space per month.

WMA also believes that a special loss study may not be cost effective for either Edison or DMS-2 customers. If one is required, the WMA recommends that its 8.02% discount be adopted and that a balancing account be established to record the amount paid DMS-2 customers for losses. After the study is concluded, WMA suggests that any adjustment to the discount based on under-payments or over-payment be included in establishing the discount in Edison's next general rate case. WMA believes this approach is needed to ensure that mobilehome park owners do not wait another three years to receive an allowance for costs which the owners admittedly incur.

WMA states that its position in this proceeding is distinguishable from that which it asserted in the PG&E proceeding. Specifically, WMA notes that its current recommendation is not based on Edison's entire distribution system and includes a balancing account proposal. WMA also asserts that since losses are a small percentage of all of the kilowatt-hours used by each resident, the cost is therefore a small percentage of each resident's total bill and its impact on the discount should be irrelevant.

Edison challenges the WMA's inclusion of an allowance for distribution energy losses on the following grounds: (1) it is not based on a loss study, (2) it is based on Edison's entire distribution system and therefore may not in many instances be applicable to mobilehome parks, (3) it increases the discount of over 40% from the currently authorized discount, and (4) it fails to recognize that the typical mobilehome park owners are compensated for Edison system losses through the domestic tariff. In Edison's view, the absence of a study and WMA's reliance on Edison's entire distribution system renders WMA's adjustment an uneducated guess unrelated to the losses specifically incurred by mobilehomes.

Edison also rejects WMA's suggested balancing account. Edison believes that such a proposal would be administratively burdensome and contrary to Commission policy to limit the use of balancing accounts to address major issues affecting all of Edison's customers.

In this proceeding, WMA has obviously attempted to refine its method of estimating the distribution energy losses incurred by mobilehome parks after first proposing such an allowance for PG&E. Despite this effort, we still find WMA's proposed approach to be flawed. WMA again has considered the general level of losses at the primary and secondary distribution levels, which although experienced in some part by mobilehome parks, the exact level is unknown. We, in fact, know of no way in which that level can be properly determined without a line loss study.

In the absence of a line loss study, WMA asks that the Commission implement a balancing account for mobilehome park customers. We note, as Edison has, that balancing accounts have been reserved for major proceedings affecting all utility customers. We find unwarranted therefore the imposition of this administrative burden for a single cost related to a specific customer group, the representative of which does not even support the very study needed to identify the existence and extent of the costs in question.

With respect to WMA's assertion that losses represent a small portion of overall bills, we note that our focus is on the discount for which WMA's allowance for distribution energy losses would represent a significant portion. The magnitude of the increase in the discount caused by an allowance for distribution energy losses requires even more that the Commission be assured of the accuracy of the estimate on which that allowance is based.

For the foregoing reasons, the Commission will not adopt WMA's estimate of distribution energy losses nor will we provide for an allowance for those losses in the DMS-2 discount at this time. The only remaining issue is whether Edison should be required, as PG&E was, to conduct a study to analyze the existence and extent of these losses.

Based on the fact that mobilehome park owners do incur distribution energy losses which cannot be properly assessed in the absence of such a study, we find reasonable the undertaking by Edison, in cooperation with WMA, of a study to determine the actual line losses incurred by submetered mobilehome parks. This study, to be completed by Edison's next general rate case, will ensure that the costs associated with those losses are properly reflected in the DMS-2 discount.

b. Fixed Rate Charges

In a departure from its approach in previous years, Edison has proposed in this proceeding to use a nonlevelized, as opposed to a levelized, fixed charge rate in determining the mobilehome park discount. Edison states that this change is based on its interpretation of the applicable code section, California Public Utilities Code Section 739.5. Edison states that Section 739.5 provides that the discount cannot exceed Edison's average cost that it "would have incurred in providing comparable service directly to the users of the service." According to Edison, the use of a levelized fixed charge rate in calculating the discount for the test year (1988) would result in the discount exceeding Edison's average cost of service. Edison asserts that this average cost can only be produced by using the nonlevelized fixed charge rate.

WMA objects to Edison's use of the nonlevelized fixed charge rate to calculate the DMS-2 discount in this proceeding. According to WMA, the fixed charge rate, which is used to compute the total annual cost of capital investment, has the same value for all of the years during the useful life of the asset when it is levelized. A nonlevelized fixed charge rate, in contrast, changes value for each year of useful life to reflect changes in return, taxes, and book value. WMA states that, based on this distinction between the two rates, the nonlevelized fixed charge rate is higher than the levelized fixed charge rate in the early years and lower in the later years of the useful life.

WMA asserts that because Edison relied on levelized fixed charge rates in the earlier years of the discount, it will have understated the costs in those years should it now be permitted to change to a nonlevelized fixed charge rate. The DMS-2 customer, in WMA's opinion, is therefore deprived of the full cost of the assets by this change in accounting methodology. To make this change, WMA also believes that Edison should have first determined a true need for doing so and then, if the change were warranted, ensure that its figures were adjusted to make up for the earlier deficit.

WMA contends that Edison's use of the nonlevelized fixed charge rate is inappropriate for these additional reasons: (1) Edison's interpretation of Section 739.5, as requiring this change, is "highly technical"; (2) the change will require complex accounting adjustments, a result disputed by Edison; and (3) the change will bring instability to the discount amount. WMA also asserts that, even if a nonlevelized fixed charge rate were used, Edison's calculation is flawed as it fails to identify the true average fixed charge rates for all assets in each account. For all of these reasons, WMA urges that, in the absence of a line loss allocation, the DMS-2 discount be fixed at $7.82 per space per month based on the application of the levelized fixed charge rates.

We share WMA's concern with Edison's decision to switch from using a levelized to a nonlevelized fixed charge rate in calculating the DMS-2 discount. We find that Edison's reliance on its interpretation of Section 739.5 alone is not sufficient to warrant a change which could have serious economic repercussions for the affected customer group. The distinction between levelized and nonlevelized fixed charge rates makes inquiry into the impact of using the levelized fixed charge rates for many years and switching now to a fixed charge rate critical to our approval of that change. In order to make the change, we therefore need to know specifically whether the levelized fixed charge rate did in fact represent Edison's average costs in prior years; the extent to which those costs were under-stated or over-stated, if at all, by using a levelized fixed charge rate; and the extent to which it fails to represent Edison's average cost now.

We also find it unlikely that the Legislature intended that, for purposes of determining the mobilehome park discount, the utility's average costs were to be developed in isolation for each test year without regard to the manner in which those costs had been determined in prior years. Certainly, enough flexibility was intended under the statute to recognize the possibility that methods of calculating the average cost could result in more of the investment costs being recovered in later or earlier years depending on the accounting approach used.

For these reasons, we reject Edison's attempt to shift from the use of the levelized to a nonlevelized fixed charge rate in calculating the DMS-2 discount. If Edison believes that this change is warranted, Edison can use the opportunity of its next general rate case proceeding to provide the required justification of the change and quantification of its impact.

c. Diversity Adjustment

As stated previously, the Commission has recognized the existence of a diversity benefit which arises when a master-metered customer is billed more sales at baseline rates and less sales at nonbaseline rates than are actually consumed by his submetered tenants. (D.86-12-091, at pp. 34-35.) In this proceeding, Edison recommends a diversity adjustment similar to that adopted in PG&E's most recent general rate case to avoid subsidization of master-metered customers by the rest of the residential ratepayers due to an overallocation of kilowatt-hours at lower baseline rates. Edison proposes that a diversity adjustment (1) be made to base rate charges for Schedules DM, DMS-1, and DMS-2, (2) and that these adjustments, be set at $0.13 per unit per day for DM and DMS-1 and at $0.10 per unit per day for DMS-2, and (3) that these adjustments be updated in each subsequent general rate case proceeding.

Edison states that its diversity adjustment for DMS-2 is based on a study of Edison's total population of individually metered mobilehome customers and Edison's proposed baseline allowances and domestic rates. Edison believes that its methodology provides the best available approximation of the usage characteristics of submetered mobilehomes and reflects the diversity for this group as a whole and not the diversity of any one mobilehome park.

Edison acknowledges that an overstatement of the diversity may have resulted from its not having calculated diversity by park. Edison states, however, that due to the lack of Schedule DMS-2 data at the submetered level for all DMS-2 customers, Edison is unable to determine the actual level of diversity experienced by master-metered customers. Edison states that such a study of individually metered mobilehome customers grouped by park could be undertaken for its test year 1991 general rate case, as PG&E was directed to do in its most recent general rate case.

Edison finds that WMA's methodology for calculating the DMS-2 diversity adjustment using a nonrandom selection of 29 submetered mobilehome parks in Edison's service territory is based on an unrepresentative small sample of DMS-2 customers' data. Edison notes that 29 mobilehome parks represent less than two percent of the total DMS-2 customers in Edison's service territory and that a different set of 29 mobilehome parks could produce quite different results.

In contrast, WMA believes that the diversity benefit which appears simple in principle is much more difficult to assess in application. Until Edison performs a study of usage patterns within mobilehome parks as required for PG&E, WMA states that no diversity adjustment should be made at this time. If the Commission determines that an adjustment is necessary, however, WMA asks that the Commission rely on WMA's data from 29 submetered parks and the baseline allowances adopted in this proceeding. Based on Edison's proposed rates, WMA proposes a diversity adjustment of $1.58 per space per month.

Specifically, WMA states that its study was based on a profile of parks which closely matches the profile of DMS-2 customers and the percentage distributions of both parks and spaces across the climate zones. WMA believes that Edison's failure to study master meters in calculating its adjustment results in the disregard of the fundamental principle that diversity can only occur at the master meter level. WMA asserts that its separate consideration of each master meter identifies no diversity benefit at all. WMA also believes Edison's study is flawed because it (1) relies on kilowatt-hour sales forecasts which are inexplicably well above forecasted levels for DMS-2 customers for an identical period of time, (2) fails to consider distribution system losses, and (3) fails to account for common area usage which occurs in most submetered parks.

WMA states that for PG&E the Commission accepted PG&E's study only because no alternate approach to calculating the diversity adjustment was available. WMA believes that it has presented such a reasonable alternative in this proceeding and that to adopt Edison's studies would be to duplicate the mistakes made by PG&E. Knowing of the flaws in PG&E's study, WMA believes that Edison had the time and opportunity to improve its study, but failed to do so.

The issue of a diversity benefit is a new one for Edison's mobilehome park customers. We recognize, as we did for PG&E in D.86-12-091, however, that the need to make this adjustment exists presently to correct an inequity to other customers resulting from the billing of submetered mobilehome parks. The methodology for calculating this adjustment is obviously not perfected and requires additional data that was not available at the time of this proceeding. We also do not believe, as WMA suggests, that sufficient time was available between the issuance of D.86-12-091 and hearings in this proceeding for Edison to have "corrected" the errors in PG&E's study and performed a study based on usage patterns of individual mobilehome parks.

We are concerned, however, with the discrepancy in estimates of this adjustment between Edison's $.10 per space per day, equaling an approximate $3.00 per space per month adjustment, and WMA's proposed $1.58 per space per month adjustment. Edison has even acknowledged the potential of an overstatement of the diversity benefit in its approach. We also note, although PG&E and Edison are different utilities with different rate structures, that PG&E's discount of $1.59 per space per month for electric usage based on its proposed baseline allowances more closely mirrors the proposal of WMA.

In the absence of the appropriate study, we believe that it is reasonable and equitable to adopt a conservative estimate of the diversity adjustment. Such an estimate is represented by WMA's proposed $1.58 per space per month which we will adopt in this proceeding. We also will follow the course established for PG&E and apply this factor to reducing the submetered discount, as opposed to base rate charges as proposed by Edison. We will similarly direct Edison to derive diversity factors for its next general rate case based on the usage patterns of mobilehome parks which it individually meters. We concur with WMA that this study requires the consideration of usage related to each master meter.

d. Adopted DMS-1 and DMS-2 Discounts

Having concluded that distribution energy losses will not be recognized in the DMS-2 discount, but that the levelized fixed charge rate should continue to be used in its calculation, we find reasonable WMA's proposed discount for DMS-2 of $7.82 per space per month or $0.26 per space per day, WMA's estimated discount absent the line loss allowance. Based on our findings regarding the diversity adjustment, the actual DMS-2 discount, however, must be reduced by our adopted diversity factor of $1.58 per space per month to yield our adopted discount for the DMS-2 schedule of $6.34 per space per month.

As we mentioned previously, Edison had also proposed a submetering discount for the DMS-1 schedule and diversity factors for schedules DMS-1 and DM (a master-meter schedule closed to new customers after 1978. Specifically, Edison proposes to maintain the submetering discount for the DMS-1 schedule at its current level of $2.12 per space per month to include a diversity factor for both the DMS-1 and DM schedules of $4.00 per space per month. Edison's diversity factors for these schedules were developed based on a study which used the same methodology which yielded Edison's proposed DMS-2 diversity factor.

Although we did not adopt for PG&E a diversity factor for other than mobilehome parks, it is clear that a diversity benefit exists with respect to all master-metered customers. For this reason, we believe that adjustments for this diversity benefit should also be reflected in Edison's DM and DMS-1 schedules. The diversity factors proposed by Edison for these schedules, however, were developed based on the same methodology as was used in the study conducted for DMS-2 customers, the results of which we have not adopted. The DM and DMS-1 diversity factor proposed by Edison should therefore be reduced proportionately to reflect the difference between Edison's proposed and our adopted DMS-2 diversity factor.

We also note that the DMS-1 discount proposed by Edison does not appear to be based on a current study. Due to this circumstance, we find that the DMS-1 discount should be proportionately increased in keeping with our increase in the DMS-2 discount and should be based on an approach which maintains the current ratio between the DMS-1 and DMS-2 discounts.

We therefore adopt a diversity factor for DM and DMS-1 of $2.43 per space per month or $0.08 per space per day, and a DMS-1 discount of $2.41 per space per month which similarly converts to $0.08 per space per day. The effect of reducing the DMS-1 discount by the amount of the diversity factor is obviously to provide an undiscounted rate to those customers. We further direct Edison to conduct a diversity study for DM and DMS-1 customers for its next general rate case consistent with the study ordered for DMS-2 customers. This study should therefore focus on the usage patterns of the multifamily dwellings and mobilehome parks who are individually metered and data should be grouped at the master meter level (apartment building or mobilehome park).

e. <u>Applicability of DMS-2 Schedule to RV Parks</u>

Finally, we address the request of certain RV park owners for the inclusion of recreational vehicle parks in the DMS-2 schedule or, in the alternative, the establishment of a new, similar schedule for RV parks. The RV park owners state that these changes are needed in response to (1) the difficult economic conditions facing RV park owners; (2) the change in customers' choosing smaller, more portable, and less expensive RV units as residences in favor of large mobilehomes; and (3) the need, due to this change from mobilehomes to RVs as residential units, to ensure baseline allowances for RV owners.

The RV park owners believe that the choice of living unit should not deprive any resident of his entitlement to a baseline allowance. Further, the RV park owners assert that the permanence of the RV as a residence has been recognized by state law in which the provisions and rights of the Mobilehome Tenancy Law (Cal.Civ.Code Section 798, et seq.) have been made applicable to recreational vehicle tenants which have established a tenancy in a park for nine months or longer. (Recreational Vehicle Occupancy Law (Cal.Civ.Code Section 799.20 et seq.).)

In keeping with these laws and changed social conditions, the RV park owners proposed in their "closing" brief filed on July 31, 1987, that the Commission adopt one of the following alternatives to ensure the extension of baseline to RV tenants:

1. The definition of "mobilehome park multifamily accommodation" under Edison's tariff Rule 1 should be changed to include residential units as defined by the Recreational Vehicle Occupancy Law and the Mobilehome Tenancy Law (9 month tenancy) and to include RV parks where 50% or more of the spaces or lots submetered are leased for 30 days or longer and are occupied for nine months out of the year.

2. The DMS-2 schedule should be amended to alter the present "applicability" paragraph and to add a special condition so as to include and extend the discount to recreational vehicle parks which meet the criteria outlined in the above alternative. The RV park owners propose that the

discount for RV parks with vacancy factors and transient load would be established as a percentage of the total spaces submetered upon proof of average number of spaces occupied on a month to month basis over the past 12-month period in the park or upon actual spaces occupied on a month to month basis where the park has not established a record from which to compute the average.

3. In the absence of either of these two alternatives, a new Schedule DMS-3 should be established which would be identical to DMS-2 except for the following: (1) all references to "mobilehome" would be replaced by "recreational vehicle," and (2) the "applicability" and special conditions of the tariff would match those discussed above related to the modification of DMS-2.

The RV park owners assert that Edison objections to their proposals merely reflect Edison's unwillingness to change past practices despite a change in residential dwelling habits. Specifically, the RV park owners charge that Edison has (1) misinterpreted the application of DMS-2; (2) denied baseline benefits to individuals who have chosen to reside in a smaller, more portable dwelling unit; and (3) failed to recognize the similarities in the intentions and legal status of RV and mobilehome park owners.

Edison opposes the inclusion of RV parks under either Schedule DMS-2 or a new, similarly designed rate schedule. Edison states that it already has a rate schedule (DMS-1) which provides a baseline allowance and a discount for submetered service and which is applicable to an RV park meter that meets certain criteria. This criteria includes the installation of the park prior to December 7, 1981, and the presence in that park of exclusively nontransient, single-family accommodations used as permanent residences on a single Edison meter. Edison states that RV parks with a mixture of transient and nontransient load do not qualify for DMS-1 service and that the Commission has ruled that after December 7, 1981, single-family dwellings, in other than a mobilehome park, must have an individual meter. (D.88651, at p. 23; D.88969, at p. 57.)

Edison additionally states that the DMS-2 rate schedule is expressly limited to mobilehome parks and was designed only for such parks. According to Edison, this schedule does not take into account the RV park, but rather is based specifically on the costs to serve mobilehome parks and the reliability of the construction and maintenance of their electrical distribution systems. Edison further notes that separate California laws apply to and define "mobilehome parks" and "RV parks." Edison also states that the Commission did not intend that RV parks with transient accommodations or transient tenants receive residential baseline rates. (D.86087 at p. 9.)

Edison also argues against the Commission's consideration of the RV park owners' proposed new rate Schedule DMS-3. Edison states that this proposal was presented for the first time in this proceeding in the RV park owners' "closing brief" and that Edison has therefore not had the opportunity to analyze or respond to this proposal.

Although Edison urges the rejection of this proposal on this ground alone, Edison also asserts that the proposal is not supported by the record or by reason. Specifically, Edison believes that the same reasons which demonstrate that the DMS-2 schedule is inapplicable to RV parks also support the rejection of the proposed DMS-3 schedule. Additionally, Edison states that the new rate schedule would impose substantial administrative costs on Edison's other ratepayers related to the application and monitoring of the new rate schedule. Edison further asserts that the load and residency requirements proposed by the RV park owners are wholly inadequate to ensure the presence of nontransient, residential tenants.

WMA also opposes the inclusion of recreational vehicle parks in the DMS-2 schedule for the same reasons as those asserted by Edison. In the absence of adequate cost information and the determination of the applicability of residential rates to users of residential vehicle park spaces, WMA states that it is inappropriate to include RV parks within the DMS-2 schedule.

Like Edison, we also have significant problems with the RV park owners' specific proposals. To begin with, a review of the record reflects that none of the RV park owners' alternative rate design proposals set forth in their brief were similarly presented in their testimony. A review of the RV park owners' testimony reveals that this testimony focused on the nature of RV park tenants, the Edison billing histories of certain RV parks, and the perceived need for the application of the DMS-2 schedule to RV parks.

For the RV park owners to present specific rate design proposals in this proceeding after the close of hearings is inequitable and a denial of the opportunity of other parties to cross-examine the RV park owners and to respond to the owners' proposals. This approach also denies the Commission the opportunity to examine these proposals in greater detail to determine their impact on all residential customers and to ensure their reasonableness. For these reasons alone, we find that we are foreclosed from considering the RV park owners' proposed changes and additions to Edison's existing tariffs.

We are not foreclosed, however, from considering the need for such tariff changes in the future. In this regard, we believe that the RV park owners have actually raised two separate issues: (1) the need to apply baseline allowances to recreational vehicle tenants and (2) the need to extend a master-metered discount to RV park owners similar to that in place for mobilehome park owners.

With respect to baseline allowances, to the extent that the alleged trend toward recreational vehicles as permanent residences can be demonstrated, it may be appropriate for RV tenants to receive baseline allowances. To do so, however, the Commission would need proof of the existence of such residential use and a reasonable basis for distinguishing between transient and nontransient RV tenants. Without objective criteria to develop a baseline allowance, the Commission could not be assured that such allowances were being properly limited to residential customers only. The Commission must also consider the resulting administrative burden imposed on Edison and ensure that Edison can properly monitor its system and billing.

The burden of proving the existence of the change from mobilehome to recreational vehicle as a permanent residence has not, however, been met in this proceeding. Additionally, the record is not sufficient to determine the exact residence requirements, the need for monitoring, or the appropriate charges for master-metered and submetered service to recreational vehicles.

The application of the DMS-2 schedule to RV parks requires the further determination of the propriety of a master-metered discount being provided to RV park owners. As Edison has correctly pointed out, the development of the DMS-2 schedule was the process of both a legislative and an administrative (Commission) effort which focused on the exact costs and needs of the master-metered mobilehome park. Before any similar tariff could be adopted for the RV park, a level of analysis beyond that undertaken in this proceeding would certainly be required. That analysis would, of course, need to include consideration of the costs associated with installing, operating, and owning the submetering distribution facilities within the RV park and the propriety of applying the same statutory standards for establishing the discounts for RV parks and mobilehome parks.

As our foregoing discussion makes clear, we are not in a position in this proceeding to adopt any of the rate design changes proposed by the RV park owners. We do find, however, that sufficient reasons have been suggested by the RV park owners for this Commission to consider the need for tariff changes extending baseline allowances or master-metered discounts to RV tenants and RV park owners. We will therefore direct Edison to conduct a study of the need for and feasibility of such tariff changes and present the results of that study in its next general rate case. To undertake this task, Edison will be required to provide standards by which it can objectively judge and realistically monitor the status of the RV tenant.

C. Lighting - Small and Medium Power Customer Group

Testimony in this proceeding on the rate design to be adopted for the small and medium power customer group centered on the recommendations of Edison, PSD, and SCRUB. Edison and PSD in their joint exhibit on rate design (Exhibit 87) reached agreement on most of the components of these rate schedules. SCRUB and Edison, however, failed to agree on the issues of conjunctive billing and the waiver of non-time related demand charges for schools.

The agreement reached by Edison and PSD includes the following:

1. Schedule Changes. PSD has agreed to Edison's proposal to eliminate Schedule GS-1, creating two new schedules in its place. The first would be GS-SP, for single-phase customers. The second would be GS-TP for three-phase customers, but its use would be limited to existing GS-1 three-phase customers, with new three-phase customers moving to the demand-metered Schedules GS-2, TOU-GS, and PA-2 or PA-1, a connected load schedule based on their operation. In addition, Edison has accepted the PSD recommendation that Schedule GS-TP be eliminated effective December 31, 1990, thus placing all three-phase customers on one of the above schedules.

2. Customer Charges. Edison and PSD agree that the customer charge for Schedules GS-2

and TOU-GS should be set at $30.00 per month. In addition, Schedule TOU-GS should include a $7.00 per month meter charge.

3. Demand Charges. Edison and PSD agree that for Schedule GS-2, the summer time-related demand charge should be set at $5.70 per kW with no demand charge in the winter. Edison and PSD also agree that the non-time-related demand charge should be set at $2.60 per kW of current billing period demand or 50 percent of the highest demand over the previous 11 months, whichever is greater.

4. Energy Charges. Edison and PSD agree that energy charges for proposed Schedules GS-SP and GS-TP should not be seasonally differentiated and should be set residually to collect any revenue requirement not collected through the customer charge. Edison and PSD agree that Schedule GS-2 should not include seasonal differentiation of the energy charges and should have a blocked energy rate set at 5.0 cents/kWh for all kWh in excess of 300 kWh/kW. The energy rate for the first block is proposed to be determined residually to collect the remainder of the revenue requirement not collected through the customer charge, demand charges, and second block energy rate.

These agreements of PSD and Edison were not opposed by any other party. We find, for the most part, that each is reasonable having been based on sound rate design principles. The only exception is Edison's and PSD's recommendation to "ratchet" the demand charge. "Ratcheting" refers to the setting of the demand charge at a percentage of the highest demand over a fixed period of time. In this proceeding, Edison has proposed ratchets for all demand-metered schedules. Because this issue was discussed in greater depth for the large power customer group, we reserve our discussion of that issue to that portion of this order. We have found, based on that discussion, however, that ratcheting of demand charges is inappropriate. Consistent with that finding, we similarly do not adopt Edison's and PSD's ratchet proposal for demand charges under the small and medium power rate schedules.

1. Non-TOU Schedules

For the non-TOU schedules for small and medium power customers, the remaining issues between Edison and PSD involve the calculation of customer charges and energy rates. With respect to customer charges, the parties agree that these charges should be set on a daily basis. Edison, however, proposes that the charges be set at 25 cents per day, while PSD recommends a rate of 15 cents per day. PSD states that its daily rate is derived from a $4.50 per month customer charge based on marginal customer costs.

Edison states that its approach to calculating the non-demand customer charge is more appropriate than PSD's method because it is designed to recover a greater percentage of fixed costs in the fixed customer charge without producing adverse bill impacts. We concur with Edison and will adopt its proposed daily customer charge of 25 cents per day for Schedules GS-SP, GS-TP, and TC-1.

Edison states that it has proposed the same methodology for setting the Schedule TC-1 energy rate as proposed for Schedules GS-SP and GS-TP. PSD has, in contrast, set the Schedule TC-1 average rate the same as the proposed Schedule GS-SP/TP average rate based on similarities in the size of customers served on Schedules GS-SP, GS-TP, and TC-1. Edison asserts that although TC-1 customers are similar in size to GS-SP and GS-TP customers, their usage characteristics are dissimilar since traffic lights operate 24 hours per day. In Edison's opinion, their rate should therefore not be arbitrarily set at the average of GS-SP and GS-TP whose load characteristics are primarily on-peak.

To the extent possible, it is our intent in rate design to provide proper price signals based on marginal costs and the customer's usage characteristics. We believe that Edison's proposed Schedule TC-1 energy rate accomplishes this goal and should be adopted.

2. Time-Of-Use Schedules (TOU-GS and TOU-GS-SOP)

Both Edison and PSD propose that Edison's Schedule TOU-GS, applicable to small and medium power customers with maximum demands below 500 kW, should be kept open and that a new schedule, TOU-GS-SOP, should be made available to the same group of customers. The structure of Edison's proposed rate Schedule TOU-GS-SOP is the same as the TOU-8-SOP rate schedule and includes a fourth time period called the "super off-peak" period for the hours between midnight and 6:00 a.m. Edison believes that this proposed rate schedule can promote cost effective usage during the super-off-peak period and thus help mitigate its minimum load problem. The availability of the option, in Edison's opinion, will also help shift loads such as air conditioning from on-peak to off-peak by giving cost-effective incentives and promoting thermal storage systems.

With respect to the charges under these rate schedules, Edison and PSD have agreed on the customer charges, the demand charges, and the methodology for determining the amount of revenue to be collected from the TOU-GS and TOU-GS-SOP rate schedules. The revenue allocation for these rate schedules should be based on an equal percent of present rate revenues consistent with our previous adoption of Edison's proposed intra-class revenue allocation. The only exception to this finding is for TOU-GS and GS-2 the revenue allocation for which, as previously discussed, is determined by applying the adopted rates to the billing determinants proposed for those schedules by Edison and PSD.

Since the conclusion of the hearings, PSD and Edison reached further agreement on certain modification to the TOU-GS schedules. These modifications are as follows:

1. The customer charge is reduced from $250/month to $30/month;

2. The non-time-related demand charge is reduced from $2.70/kW to $2.60/kW. The above changes are made so that the customer and non-time-related demand charges conform with the equivalent charges on the GS-2 rate schedule;

3. The time-related demand charges are reduced to conform with the corresponding charges reflected in the joint exhibit (Exhibit 87); and

4. The revenue shortfall resulting from the above adjustments is allocated to the summer on- and mid-peak and winter mid-peak energy charges on the bases agreed to by the parties.

For the TOU-GS and TOU-GS-SOP rate schedules, the only difference between Edison and PSD was the calculation of the energy charge. Instead of using the EPMC approach advocated by PSD, Edison set the off-peak and super off-peak energy charges at predetermined levels of 5.0 cents/kWh and 3.7 cents/kWh with the other time-differentiated energy charges being set on an EPMC basis. Edison states that this approach is consistent with the TOU-8 and TOU-8-SOP rate schedules and ensures a stable rate level for the off-peak and super off-peak energy charges.

We find that the agreements reached by Edison and PSD result in rate structures for the TOU-GS and TOU-GS-SOP schedules which are consistent with our current rate design policies and principles. The two schedules not only offer significant options to customers served under these schedules in terms of controlling energy consumption and costs, but also ensure recovery of the revenue allocated to the class. We therefore find reasonable and adopt the rate structure for TOU-GS and TOU-GS-SOP to which Edison and PSD have agreed and direct the implementation of these schedules in the manner proposed by these parties. To ensure consistency with our other findings, however, no "ratcheting" of demand charges should be included in these schedules.

With respect to the sole issue in dispute, we find reasonable and adopt the energy charges for the two schedules as proposed by Edison. Edison has adequately demonstrated that these charges are required to ensure consistency and stability in rate levels and between rate schedules.

3. Issues Impacting School Districts

In this proceeding, SCRUB has requested consolidated or "conjunctive" billing at a single rate of all meters at a single school site and all meters within an entire school district. SCRUB also asks that the non-time related demand charge for distribution be waived for school districts if that district enters a formal agreement with Edison to limit energy usage during peak periods to a predetermined level. Edison opposes both of these recommendations.

a. Conjunctive Billing

Conjunctive billing for schools was addressed in PG&E's most recent general rate case. In D.86-12-091 in that proceeding, we found that it was reasonable for PG&E to provide schools taking service from more than one meter at the same site with the opportunity to have their total usage consolidated for billing purposes. (D.86-12-091, at pp. 81-82.) This same finding, however, was not extended to consolidated billing for multiple sites based on our conclusion that no distinction should be made between two or more customers taking service at individual sites and one customer taking service at multiple sites.

We therefore required PG&E to offer conjunctive billing for multiple meters at a single school, and in its next rate case, address the propriety of expanding conjunctive billing to all customers. (D.86-12-091, at p. 82.) Under the terms of that billing, the school was not to be required to pay for any special facilities needed to achieve consolidation of its bills, but it would be required to pay for the administrative and facilities costs associated with providing service on one site at different locations. (Id., at pp. 81-82.)

In response to D.86-12-091, PG&E filed an advice letter earlier this year seeking Commission approval of two new forms related to conjunctive billing for schools. Of these two billing forms, one reflected on the cost of allocated facilities necessary to provide service at multiple sites, while the other, a simpler form, involved combining meter readings from all accounts at a site and billing them under one rate. These forms were the result of an agreement between PG&E and SCRUB who had also agreed that the forms should be offered on a limited, experimental basis. Specifically, the parties agreed that, due to the costs and complexities of the facility cost agreement, this form would be offered on a test basis to a limited number of schools. The second, simpler option would be offered as a further experiment limited to primary and secondary schools.

By Resolution E-3045, dated August 26, 1987, PG&E was authorized to file these two new forms. The resolution also directed PG&E in its next general rate case to evaluate this conjunctive billing experiment on the basis, among other things, of its revenue effect, the need for its continuation, and the propriety of making the option available to other types of customers.

In this proceeding, as stated previously, SCRUB asks that Edison be required, as PG&E was, to undertake conjunctive billing for schools. SCRUB's request, however, includes not only conjunctive billing for all meters at a single school site, but also all meters at multiple sites within a single school district.

With respect to this latter request, SCRUB believes that conjunctive billing for multiple sites is required to permit the school district to practice load management and to accurately determine the economics of self-generation. SCRUB states that this type of billing could be undertaken by Edison on an experimental basis subject to certain conditions. These conditions would include (1) Edison's installation of the necessary equipment and implementation of the necessary billing procedures, (2) computation of the bill under the rate schedule that is applicable to the combined usage, and (3) recovery by Edison of the cost of any additional facilities and efforts related to conjunctive billing directly from the districts receiving the service in the form of predetermined, standard monthly service charges.

Edison states that it objects to conjunctive billing for schools for both single sites and multiple sites. Edison believes that conjunctive billing is not cost-effective, "bundles" rather than "unbundles" generation, transmission, and distribution costs; and is not a proper means of reflecting non-time related demand on its distribution system.

With respect to this latter point, Edison believes that inequities in rate design will result if the "benefit" of conjunctive billing is extended to one customer group. Specifically, Edison asserts that diversity among accounts is already recognized by virtue of the design billing parameters which are based on historical "noncoincident" demands. Edison states that as these billing parameters decrease under conjunctive billing, the demand charge must increase proportionately to recover Edison's cost of service. Edison therefore concludes that if only schools are permitted conjunctive billing, all other customers, other than schools, would be adversely affected. Edison notes, however, that conversely if all multiple-site customers were entitled to conjunctive billing, the concept would produce little or no benefits since the rate would increase as billing parameters decreased.

Edison concludes therefore that SCRUB's proposal must be evaluated not just on the basis of the benefit, if any, received by schools, but whether all of Edison's customers would be positively or adversely affected. Due to the high administrative, metering, and billing costs, Edison believes that the final result of conjunctive billing will be an adverse impact on all other ratepayers.

While Edison has raised appropriate concerns regarding conjunctive billing, we do not believe that these concerns warrant our rejection of conjunctive billing for multiple meters at single school sites on an experimental basis. We continue to believe that this form of conjunctive billing, subject to the limitations imposed in D.86-12-091, will permit the schools to realize the benefit of consolidated billing without the need to incur any additional costs just to attain that goal. We also believe, however, that D.86-12-091 as well as Resolution E-3045 reflect our need to ensure that the asserted benefits of conjunctive billing are realized. As authorized in that resolution, PG&E's offering of conjunctive billing for schools is on a limited, experimental basis subject to an evaluation of the program in PG&E's next general rate case. This evaluation will examine conjunctive billing on the basis of its revenue effect, the need for its continuation for schools, and the need for its expansion to other customer groups.

For these reasons, we find that it is appropriate to order Edison to offer conjunctive billing for multiple meters at a single school site consistent with D.86-12-091 and Resolution E-3045. We will therefore require Edison to file an advice letter implementing the necessary tariffs or forms to accomplish this goal and to perform for its next general rate case an evaluation of conjunctive billing for schools and for all customers consistent with these decisions.

We are unpersuaded by SCRUB's arguments to extend conjunctive billing beyond the single school site. The reservations expressed by Edison regarding single site conjunctive billing already require that that program be instituted only on a limited basis. We do not believe that sufficient justification has been provided to enlarge that program to include conjunctive billing for multiple sites.

b. Waiver of Non-Time-Related Demand Charges

SCRUB also proposes that the non-time-related demand charge for distribution be waived for schools, if the school district enters a formal agreement with Edison to limit energy usage during peak periods to a predetermined level. SCRUB's request is based on the annual electrical usage pattern of schools and the flexibility which schools have in summer scheduling. According to SCRUB these factors create a unique opportunity to free electricity for use on the Edison system during peak times and save costs for both Edison and school districts. By adopting its recommendation, SCRUB testified that net marginal cost savings to Edison of $23.88 for each peak kw not used by a school and made available to the system would be realized.

Edison opposes SCRUB's proposal as unnecessary since the proposed rates applicable to schools are "unbundled" and already reflect the appropriate reduction in summer time-related demand charges. According to Edison, if a school has lower demands in summer months, this lower demand will be reflected in a reduced time-related demand charge. Edison asserts that this charge properly reflects the cost of distribution facilities which is determined by the highest demand occurring throughout the year. Edison therefore believes that to reduce the non-time-related portion of the demand charge would defeat the purpose of unbundling the rate.

As we have previously indicated, we have rejected Edison's proposal to ratchet demand charges. This conclusion is equally applicable to demand charges for schools

We concur with Edison, however, that "unbundled" and time-differentiated rates charged to schools are adequate to ensure that the schools pay those costs reasonably attributable to their usage characteristics. Any further refinement of the rates under which schools are provided service is therefore unnecessary at this time. SCRUB's recommended waiver for schools of non-time-related demand charges should therefore be rejected.

D. Large Power Customer Group

Edison's large power customer group receives service primarily under the mandatory time-of-use schedule, TOU-8. In addition to the TOU-8 schedule, these customers are offered optional time-of-use schedules providing interruptible and super-off-peak (SOP) rates and service, as well as real-time pricing. Additionally, standby service is provided to those customers who require backup service for their own generation facilities. In this proceeding, Edison has further proposed two contract rate options for this customer group.

Edison and PSD have reached substantial agreement on the rate structure for these schedules. Significant issues, however, remain between these two parties, as well as numerous interested parties including FEA, CMA, IU, CLECA/CSPG, DGS, and the CSC. The schedules and the positions of the parties are reviewed below followed by our resolution of each issue.

1. TOU-8

Edison and the PSD are in agreement with respect to virtually all aspects of the basic TOU-8 schedule with the exception of the development of the TOU-8 energy charges. Both Edison and PSD agree that in the event that the adopted revenue requirement is different from that upon which their proposed rate design is based, the differences should be reflected in the energy, as opposed to demand, charges.

FEA, CMA, IU, and CLECA/CSPG have also provided testimony recommending energy and demand charges for the TOU-8 schedule. These parties state that their recommendations emphasize the need to implement cost-based rates for the TOU-8 schedules while preserving rate stability.

a. TOU-8 Rates By Voltage Level

In D.84-12-068 in Edison's last general rate case, the Commission adopted a two-step approach for revising the manner in which voltage differences within the TOU-8 customer group were recognized. The first step, which was taken in D.84-12-068, was to adopt PSD's voltage discounts for each of the three voltage categories of below 2 kV, 2 kV to 50 kV, and greater than 50 kV. The second step, which was to be taken in this proceeding, was the division of the TOU-8 rate schedules into the three voltage categories with rates based on marginal costs developed for each of those subgroups.

In this proceeding, PSD submitted a proposal to establish the three TOU-8 voltage levels as separate schedules. Edison, while first declining to recommend this approach, subsequently supported PSD's proposal. PSD's proposal was also supported by FEA and IU. PSD, FEA, IU, and CLECA/CSPG agree that separate rate schedules by voltage level yield rates which reflect the different costs of service imposed at each voltage level and the different load characteristics related to each of those levels.

We find that PSD's proposed TOU-8 subschedules are in keeping with our decision in Edison's last general rate case and provide rates related to the cost of service and load characteristics of TOU-8 customers by voltage level. This approach therefore further refines and improves the price signals which TOU-8 customers receive.

b. Demand Charges.

Agreement was also reached between Edison and PSD on all demand charges (time-related and non-time-related) for the large power customer group. Several interested parties, however, proposed different demand charges as well as "rate limiters" designed to avoid rate shock by certain customers. The issue of rate limiters is discussed in a separate section following our consideration of the TOU-8 schedule and other large power customer rate options. All parties state that their proposed demand charges are based on marginal costs.

(1) Parties Positions

Edison and PSD assert that the demand charges to which they have agreed best reflect marginal demand costs without producing adverse bill impacts. In the case of time-related demand charges, Edison and PSD have agreed to eliminate winter off-peak demand charges and to use the higher on-peak demand charges proposed by PSD. These demand charges are set at 50% of the marginal on-peak demand costs for the on-peak period, 100% of the marginal coincident demand costs for the mid-peak period, and zero for the off-peak period.

With regard to non-time-related demand charges, Edison and PSD reached a compromise position. Edison had proposed to base this charge on the highest demand in the previous year while PSD proposed that it be the highest demand for the month. The agreement provides for the non-time-related demand charge to be the highest demand for the month or 50% of the highest demand for the preceeding 11 months, whichever is greater. PSD believes that this approach will provide an incentive to customers to reduce demand while still ensuring rates which reflect the costs incurred by the utility to meet noncoincident demand.

FEA and IU endorse the agreement reached by PSD and Edison to differentiate between time-related and non-time-related demand charges. According to FEA, such a rate design approach permits rates to reflect more accurately cost differences across time periods.

According to IU, the shift of fixed costs from the energy charge to demand charge components of the TOU-8 rate schedule should be subject only to the limitation that this change not result in adverse rate impacts. According to IU, a full implementation of EPMC for these rate components could produce unacceptably severe bill impacts for low load factor and seasonal customers because of the extremely high costs associated with summer peak demand.

To offset this result, IU proposes that the on-peak demand charge be set at 50% of the EPMC level if the Commission approves the revenue requirement proposed by Edison. In the case of PSD's proposed revenue decrease, IU acknowledges that adverse rate impacts will be less significant and proposes that the peak demand charge be set at 60% of EPMC.

As a means of recovering the remaining on-peak demand costs, IU proposes that the winter demand charge not be eliminated as recommended by PSD and Edison, but be retained at that its present level in order to recover a portion of the demand costs not recovered in the peak demand charges. Alternatively, IU recommends that the balance of unrecovered on-peak demand costs be recovered in the on-peak energy charges to ensure recovery of those costs in the same time period during which they are incurred. IU emphasizes that this approach would be merely temporary until class revenues move closer to cost in future rate proceedings. To the extent that severe bill impacts may occur despite such a demand charge limitation, IU proposes that the Commission consider and adopt "rate limiters."

CMA proposes, consistent with its marginal demand cost recommendation that demand charges should be based on the use of Edison's adopted Energy Reliability Index (ERI). The ERI, as explained earlier in this decision, is used in adjusting capacity values for QF pricing and in undertaking resource cost-effectiveness analyses. According to CMA, inclusion of the ERI in the calculation of demand charges will provide recognition of the existing oversupply of generation capacity. Based on its calculations, CMA also believes that introduction of the ERI into the demand charge determination would have the additional, desirable result of reducing the problem of rate shock which would exist if full EPMC rates were charged.

PSD opposes CMA's recommendation to apply the ERI to customer demand charges. PSD notes that the use of the ERI, used to adjust short-run marginal costs, would fail to reflect the long-term costs of the system. PSD asserts that use of the ERI would therefore prevent TOU-8 demand charges from reflecting accurate, long-term price signals on which customers could base their investment decisions and changes in production patterns.

CMA also requests that TOU-8 rates should not include a "ratchet" on maximum demand charges. The "ratchet" to which CMA refers relates to Edison's and PSD's agreement to set non-time-related demand charges at 50% of the highest demand over the previous eleven months. CMA notes that while PSD had proposed no ratchet at all originally, it compromised with Edison by agreeing to a ratchet of 50% of the highest demand over the previous eleven months. CMA submits that PSD's original position was correct and that a ratchet of any amount on a noncoincident demand charge fails to reflect costs or provide proper price signal to customers.

In response to CMA, Edison states that the proposed ratchet on demand charges is necessary to ensure Edison's recovery of the cost of distribution facilities. According to Edison, these costs are a function of the capacity of the distribution facilities installed for each customer, which capacity is defined by the customer's highest demand regardless of when it occurs. Edison states that a 12-month ratchet ensures that seasonal variations in monthly demands do not distort the appropriate price signal.

Edison also asserts that non-time-related demand charges are not designed to recover coincident demand related costs and are therefore not intended to reflect diversity. Edison further does not believe that noncoincident demand costs should be collected through energy rates a result which would occur in the absence of a ratchet. Edison states that, absent its compromise with PSD for a 50% ratchet, it would have continued to support a 100% ratchet.

(2) Discussion

We find that Edison's and PSD's agreement, for the most part, achieves demand charges which are cost-based and load-related. We do not concur, however, with Edison's and PSD's compromise on "ratcheting" of demand charges nor with the IU's suggestion of setting the demand charge at less than EPMC. Neither of these recommendations achieve our goal of providing cost-based rates and ensuring accurate price signals to the affected customer group. While we understand that IU's proposal was intended solely as a temporary, transitional device to mitigate adverse rate impacts, we believe, as explained below, that the use of rate limiters is a more appropriate means of achieving this goal.

With respect to ratchets, the Commission in recent years has sought to move away from this concept. For PG&E ratchets were used only for certain agricultural schedules. The reason for this policy is clear. Specifically, ratchets have an inequitable effect on many customers. Customers with stable levels of demand throughout the year would not be greatly affected by ratchets, but seasonal industries would see their off-season energy bills increase even though their off-season demand and energy usage would be relatively low. The ultimate effect could be discrimination in customer billings among customers with identical usage.

We believe that such a result is almost completely at odds with our efforts to accurately reflect the costs imposed by the customer on a time- and load-related basis and would require significant justification on the part of the party proposing the ratchet. We have carefully reviewed the proposal of Edison and PSD and Edison's arguments in support of the ratchet and do not find the level of justification required to adopt this approach.

Additionally, we also do not rule out the possibility, despite Edison's argument to the contrary, that diversity in demand is reflected in non-time-related demand charges over a 12-month period, a time frame which even Edison used to ensure no distortions in the price signal due to seasonal variations in demand.

Any resulting allocation of non-time-related demand costs to energy charges, as opposed to demand charges, due to the absence of the ratchet is not a sufficient reason to impose ratchets. While we seek to "unbundle" and correctly identify costs with the appropriate rate component, this effort should not be blind to detrimental impacts which may result. We therefore reject Edison's and PSD's imposition of ratchets on all demand-related meters for small, medium, and large power customer rate schedules.

As previously stated, we also do not believe it is appropriate to limit demand charges to a certain percentage of their EPMC level. In an effort to achieve cost-based rates, we believe that each individual rate component should be based, to the extent possible, on marginal cost. If adverse impacts should result due to following this approach, we believe that rate limiters, discussed later in this section, provide a more appropriate mechanism to offset those impacts while maintaining proper price signals.

Finally, we turn to the suggestion of CMA to apply the ERI to the calculation of the demand charge. Earlier in this decision, we rejected CMA's proposal that generation marginal demand costs should reflect the ERI. We found that further evidence was required to determine whether the concerns which lead to the adoption of an ERI to adjust QF capacity prices in the short-run were the same as for the calculation of marginal costs used in revenue allocation and rate design.

This finding reflects our concern, as even PSD has noted, that the purpose for which the ERI was developed and is currently being used may not be applicable to designing rates. We have directed Edison and PSD to examine the issue of the propriety of reflecting the ERI adjustment in generation marginal demand costs in Edison's next general rate case. We will similarly direct Edison to consider its applicability for rate design purposes as well.

c. <u>Energy Charges</u>

The only area of significant disagreement between PSD and Edison with respect to the TOU-8 schedule relates to the energy charge component of that schedule. CLECA/CSPG, FEA, and IU also provided testimony and argument on this issue.

Edison proposes to set the off-peak energy charge at 5 cents/kWh with the on- and mid-peak energy rates set to collect the remaining revenue requirement and to reflect marginal energy cost ratios. Edison states that its off-peak proposal is designed to reflect marginal costs as closely as possible while mitigating adverse bill impacts for some customers. In Edison's opinion, the 5-cent level provides a stable off-peak rate, making it easier, for customers to make appropriate investment decisions.

In contrast, PSD recommends that the off-peak energy rate be set at the full EPMC level. PSD further proposes that the balance of the revenue requirement for this class, including the marginal costs for the on- and mid-peak periods and the residual demand marginal costs not collected from the demand charges, should be recovered through the remaining energy charges.

In Edison's view, PSD's proposal places too much reliance on current marginal cost relationships and in turn fails to recognize the need for stability and consistency in rates. Further, according to Edison, PSD's proposal results in allocating all uncollected capacity costs to the on- and mid-peak period energy rates based on loss of load probabilities (LOLP). Edison states that this approach will result in an overstatement of on-peak costs and an understatement of off-peak costs which in turn could encourage uneconomic on-peak bypass.

In taking issue with Edison's approach, PSD asserts that Edison's number is not based on a formula, but is apparently intended to provide a stable round number as a base and to ensure some contribution to margin. PSD states that the problem with Edison's "stable" rate is that it may make too much contribution to margin and will act as a disincentive for customers to shift off peak. This result, according to PSD, conflicts with Edison's with its minimum load concerns.

CLECA/CSPG support PSD's proposed off-peak rate. CLECA/CSPG state that this rate is cost-based, is consistent with PSD's EPMC allocation methodology, and results in relatively low off-peak rates encouraging off-peak consumption. CLECA/CSPG share PSD's concerns that Edison's 5 cent off-peak energy rate is not cost-justified and may discourage desirable incremental sales in the off-peak period. CLECA/CSPG note that Edison has admitted that this off-peak energy rate is well in excess of marginal energy cost and that its justification for the rate is based only on its potential for stability and mitigation of adverse bill impacts.

FEA asserts that cost-based rates require that demand costs be collected through demand charges and energy costs through energy charges. FEA therefore recommends removing demand costs from off-peak and mid-peak energy charges and setting those charges at marginal cost. Because customer impact considerations do require gradual movement toward cost-based rates in some instances, however, FEA also recommends that rates for primary and secondary customers be set to collect a portion of the demand costs through on-peak energy charge.

IU recommends that the on-peak energy charge include on-peak demand costs only as an alternative means of recovering those demand costs not recovered under IU's proposal for demand charges to be set at a percentage of EPMC. IU notes that this approach is only temporary until a full EPMC revenue allocation is achieved and that otherwise IU supports the recovery of fixed costs in demand charges.

We find reasonable and adopt Edison's proposed off-peak energy charges. This step is necessary to ensure consistency between the TOU-8 and TOU-GS schedules and to mitigate any adverse effect which might result from customers having to change schedules. We are again allocating the TOU-8 interruptible credits on an EPMC allocation basis (vs. incurrence), as agreed to by Edison and staff and reflected in the Appendix of the Proposed Decision. Based on the current revenue requirement and revenue allocation methodology, this allows us to preserve the appropriate relationships between energy rates for TOU-8 Secondary, TOU-8 Primary, and TOU-8 Subtransmission.

2. <u>Rate Options</u>

In this proceeding, several rate options were proposed by Edison and PSD for customers served under the TOU-8 rate schedule. These options include a super-off-peak (SOP) option, various interruptible options, two separate contract rate options, and a real-time pricing option. The parties also focused on changes to standby rates offered for backup service to those customers with their own generation facilities. In addition, to Edison and PSD, numerous interested parties responded to these proposals and offered their own recommendations. The parties' positions on each of these options is reviewed below followed by our discussion and resolution of each of the issues presented.

a. <u>Real Time Pricing</u>

Real time pricing is an experimental program designed to provide innovative ways in which customers can respond to costing periods which are more narrowly defined than the normal time-of-use periods. In this proceeding, PSD has proposed schedule RTP (real time pricing). Edison has agreed to accept PSD's hourly marginal costing and rate design methodologies for this proposed schedule, and both parties have agreed to the phase-in methodology and program expansion rate related to its implementation.

PSD states that the real time pricing periods reflected in the RTP schedule represent times when the utility system is often most strained. PSD believes that the real time pricing program will therefore not only permit customers to dramatically increase their control over their energy costs, but also enable the utility to reduce its costs.

We find that PSD's real-time pricing proposal is reasonable and should be adopted. The experimental program designed by PSD achieves the program goals of providing more specific price signals than are available under current time-of-use rates which will in turn serve to control both customer and utility costs.

b. Schedule TOU-8-SOP

In addition to its real-time-pricing proposal, PSD in this proceeding also proposed a TOU-8 schedule with super-off-peak (SOP) rates. According to PSD, SOP rates are closely related to real time pricing, establishing an additional time of use period during which energy rates are lowered below the off-peak rate. PSD believes that this rate structure provides an opportunity for Edison to address its minimum load "problem" by providing customers with an incentive to move their consumption to the SOP periods. Edison generally agrees with PSD's TOU-8-SOP rate proposal, including the redefined TOU periods and proposed rate structure.

The only difference between the parties is the method which each has used to estimate the number of customers who will move from TOU-8 to TOU-8 SOP and the revenue shortfall which will in turn result. Edison estimates approximately 730 customers will have the incentive to move to the TOU-8 SOP rate with a resulting revenue shortfall of $12.7 million. PSD estimates approximately 125 customers will be likely to change schedules based on the criterion of requiring a customer's rates to improve by 5% before assuming that a change would be made. This difference impacts the exact rates to be charged TOU-8-SOP customers since the parties agree that the revenue deficiency would be added to the demand and energy charges of the large power customer group on an EPMC basis.

PSD states that its method was based on estimating, through multiple iterations, which customers would choose each schedule and designing both TOU-SOP and TOU-8 schedules around the assigned customer group. Edison states that under its approach, a first iteration TOU-8-SOP rate based on marginal cost was designed and the revenue deficiency resulting from the migration of customers to this hypothetical schedule was determined. A second iteration of the rate was then designed to recover this revenue deficiency.

Edison believes that PSD's methodology is unnecessarily complex, involving multiple iterations to achieve a "stable" level of customers benefitting from the schedule, and results in a TOU-8-SOP rate that is too high to attract a reasonable number of customers. Under Edison's methodology, 98 TOU customers will benefit by more than 5% of their TOU-8 bill for a total benefit (or shortfall) of approximately $6 million. Under PSD's methodology, Edison states that the option would be attractive to a maximum of 48 TOU-8 customers which if all selected the PSD's rate option would produce approximately a $1.6 million revenue deficiency. PSD charges that Edison's approach is based on a simpler method which has little theoretical basis and only by coincidence achieves similar rates.

CLECA/CSPG support PSD's proposed TOU-8-SOP schedule. CLECA/CSPG finds a multitude of benefits from this schedule including providing opportunities for customers to respond to changes in utility costs, greater certainty than real time pricing, and stimulation of sales in the super-off-peak period. CLECA/CSPG also believe that the schedule will provide benefits to all customers in the form of increased sales, the prevention of uneconomic bypass, the building of customer satisfaction, and the reduction in the need for Edison to negotiate separate contract rates with its customers.

The need for a TOU-8-SOP rate option is clear. This option is another step toward cost-based rates which provide customers with the most accurate price signals regarding their use and an opportunity to change those usage patterns to reduce costs. Edison has indicated that it is also assisted by such a schedule as it encourages consumption and increases sales in the off-peak period thereby offsetting any minimum load "problem" which it might experience.

We have reviewed the methods by which Edison and PSD have attempted to estimate the number of customers who will migrate from the TOU-8 schedule to TOU-8-SOP and find a significant difference between these estimates. We believe that PSD's approach, which was based on several refinements of its estimate, may provide a more accurate and conservative basis for determining the estimated change. We are reluctant to require that the large customer group shoulder a significant revenue deficiency without a greater degree of assurance that this level of migration will result. We therefore adopt as reasonable PSD's proposed TOU-8-SOP time periods, rate structure, and rates.

c. Interruptible Rates

Interruptible rates have been available as options to Edison customers for some time. These schedules allow a customer who has less need for guaranteed service reliability to receive a lower rate in exchange for interruptions in his service. These lower rates appear as discounts provided under the interruptible schedules.

Edison has several existing interruptible schedules, I-1 through I-5. These schedules vary with the size of qualifying customer, the required degree of notice for interruption, and other factors. In this proceeding, Edison originally proposed that its interruptible schedules should remain unchanged with the exception of eliminating Schedule I-4, a recommendation to which PSD agreed due to the lack of use of this schedule by interruptible customers. In its testimony, however, PSD proposed the closing of Schedules I-2, I-3, and I-5 to new customers and the establishment of a new schedule, I-6. Schedule I-1 is already closed to new customers. PSD also proposed two new interruptible Schedules TOU-8-SOP-1A and TOU-8-SOP-1B, which combine features of TOU-8-SOP and I-6.

(1) Parties Positions

PSD asserts that the interruptible discounts should be based on the value of the system capacity at the time of interruption. PSD states that the present interruptible schedules are not cost-based. PSD therefore proposes that the I-2, I-3, and I-5 schedules be closed and that the new schedule I-6 be established.

The newly proposed schedule, I-6, is described by PSD as being similar to TOU-8, but with four time periods instead of three. The four would include three regular time periods like those included in TOU-8 and reflect the applicable unbundled components of system savings, i.e., energy and demand. PSD states that demand charges in these periods would be adjusted by the same ERI used to adjust QF capacity payments in order to reflect the value of the demand reduced by these interruptible customers.

PSD states that the fourth time period which it established in Schedule I-6 represents the 40 hours in the summer which are most likely to experience a call for interruption based on loss of load probabilities (LOLP). PSD states that a failure to interrupt when requested during those periods would lead to a penalty rate being imposed. PSD has based this penalty on the value of the service at the time of the interruption request. Under the I-6 schedule, PSD has also provided that customers could, as with I-3 and I-5, choose to designate a level of firm demand not subject to interruption. PSD states that its proposed I-6 schedule would allow a customer to select either immediate interruptibility or 1-hour notice. I-6 would be available to standby customers, including cogenerators for whom current Schedules I-3 or I-5 are not available.

During hearings in this proceeding, Edison also endorsed the concept of an I-6 schedule. Edison, however, differed with PSD with respect to assumptions relating to the period of time during which the value of future capacity is to be discounted, the basis on which capacity is to be valued, and the choice of ERI to be applied to that discount. Edison states that the ERI assumption is critical since interruptible rates are highly sensitive to that assumption.

With respect to Edison's assumptions, PSD particularly objects to Edison having based the value of capacity on the marginal cost of generation only. In contrast, PSD states that it has based this value on the marginal costs of generation, transmission, and distribution.

Interested parties to this proceeding generally supported the establishment of an I-6 schedule. Among these parties, CLECA/ CSPG believes that PSD's proposed I-6 is a viable new interruptible rate option whose design is more directly tied to the overall large power rate design than is the current interruptible rate design. Edison's proposed I-6 schedule is flawed, in CLECA/CSPG's view, for its failure to consider the value of saved transmission and distribution capacity valuing interruptibility to utilities.

CMA believes, however, that interruptible rates should be based on the cost of serving the interruptible customer and not the value of curtailability in an excess capacity situation. For a cost-based interruptible rate, CMA states that the existence or non-existence of excess generation capacity is irrelevant and that those rates must ultimately reflect a cost, and not a value, analysis. Because such a cost analysis was not presented in this proceeding, CMA asks the Commission to consider such cost issues in the future.

CMA also asserts that while penalties should exist for failures to curtail or interrupt, those penalties should be reasonable. In CMA's opinion, the existing graduated penalty provisions of Schedule I-5, adjusted to the amount of interruptible discount provided in the I-6 schedule, should be fully adequate. The concept of an escalating penalty is, in CMA's view, far more reasonable than PSD's and Edison's proposal to eliminate the discount ($33/kw/year for Edison and $80.80/kW/year for PSD) for a single failure to curtail. CMA also argues that subsequent failures using this approach would produce charges for service far in excess of firm rates.

While the parties concurred in the need for an I-6 schedule, there was substantial disagreement on whether the I-3 and I-5 schedules should in turn be closed to new customers. The I-3 and I-5 schedules have an existing "ever greening" provision requiring that a customer give Edison 5 years' notice in order to discontinue service under this schedule. These schedules, however, do not provide a notice period governing Edison's discontinuance of the schedules.

PSD states that it is aware customers incur some costs in adapting their facilities to interruptibility. As a compromise to accommodate the transition from I-3 and I-5 to the I-6 schedule, PSD therefore recommended in its brief that the Commission allow Edison to take new customers on the I-3 and I-5 schedules, but that these two schedules be closed after 1990 in favor of I-6 exclusively.

Edison does not believe that either I-3 or I-5 should be closed to new customers. Edison states that its present I-3 and I-5 rates are far more than just interruptible options. These two schedules, according to Edison, are the only available large power rate options which currently result in an average rate which is roughly equivalent to what rates should be if they were based on EPMC. Edison states that these rates are therefore needed until a full EPMC revenue allocation is achieved to permit Edison to compete with uneconomic alternatives.

Edison also states that the proposed I-5 rate was specifically designed to meet the intent of Section 743 of the Public Utilities Code requiring Edison to provide sufficient incentives to steel and food producers. Edison states that PSD did not consider this intent in its proposal and therefore did not develop a rate for that schedule designed to permit Edison to compete with rates available in other states.

If PSD's current recommendation to keep Schedules I-3 and I-5 open through 1990 were adopted, Edison believes that there would be no need to decide the issue of the status of these schedules in this proceeding. Edison states that since its next general rate case will be undertaken in 1990, the disposition of the I-3 and I-5 schedules is best left to that proceeding.

CLECA/CSPG similarly advocate the retention of Edison's I-3 and I-5 schedules. According to CLECA/CSPG, being on interruptible rates with the present level of incentives is the only way its industry members can achieve low enough rates to economically compete in their difficult markets.

CLECA/CSPG assert that I-3 and I-5 should be kept open in recognition of the long-term commitments which the interruptible customers have made to the utility and the substantial investment of these customers in protective and load-shedding equipment needed for safe and timely interruptions. CLECA/CSPG state that one of the benefits of the I-3 and I-5 schedules is to bring large customers closer to the Commission's stated long-term goal of cost-based rates. The absence of these schedules will, according to CLECA/CSPG, require these customers to shift to the I-6 schedule. CLECA/CSPG assert that the rate increase to these customers caused by this change only increases the incentives for these customers to bypass the utility system, negotiate contract rates with the utility, or reduce or terminate operations in Edison's service area. CLECA/CSPG also note that rates under the I-3 and I-5 schedules are still above short-run marginal costs.

If Schedules I-3 and I-5 are to be closed as suggested by PSD, CLECA/CSPG ask that these schedules remain open indefinitely for customers who are currently on those schedules. Based on the five-year notice provision to leave the schedule, CLECA/CSPG ask that the schedules be closed to new customers no sooner than January 1, 1993, and that customers be given the opportunity to shift, if they wish, to another interruptible schedule at that time. CLECA/CSPG also recommend that if the Commission adopts the proposed I-6 schedules, those customers on the I-3 and I-5 schedules be given the opportunity to convert to I-6 at any time, due to its cost-based nature.

IU states that fairness and other sound policy considerations dictate that Edison's existing interruptible Schedules I-3 and I-5 remain open and that contracts already concluded under those schedules be honored. IU notes, as CLECA/CSPG did, that interruptible rates involve a long-term commitment by customers. According to IU, PSD's proposed elimination of these schedules ignores the fact that these customers entered contracts in good faith reliance and with a reasonable expectation of continued rate benefits justifying capital investments necessary to becoming an interruptible customer. IU also notes that in terms of avoiding bypass, many of the customers that are currently purchasing interruptible service from Edison would choose to leave the system absent the present discounts.

IU also objects to PSD's present recommendation to retain the I-3 and I-5 schedules through 1990. In IU's view, the negative impacts of even this change would be similar to those which interruptible customers would experience with an immediate elimination of I-3 and I-5.

CMA recommends the closing of Schedules I-3 and I-5 as long as the contracts of existing customers continue to evergreen. According to CMA, the need to recognize stability in rates and equity for customers who have made changes in their operations to accommodate interruptible service requires the continuance of these contracts.

(2) Discussion

In D.86-12-091, among the criteria which we applied to the design of interruptible rate options for PG&E was the continuation of the requirement of a customer commitment to a three-year contract and the imposition of penalties for failure to curtail or interrupt. With respect to the three-year contract commitment, we found it reasonable for existing customers to expect some consistency in design criteria for the life of this contract. We therefore determined that existing incentives should be maintained for the remaining life of all contracts signed prior to the effective date of D.86-12-091. For new contracts and contract extensions signed after the effective date of that order, we based the interruptible incentives on full marginal cost without adjustment. (D.86-12-091, at p. 66.)

To ensure that customers on these rate options participated in the program by interrupting or curtailing service, we also determined that a penalty should be imposed for nonconformance. For each time a customer failed to interrupt after notification for PG&E, we found that the customer should be required to pay 1.1 times the incentive received in that month for the load not interrupted or curtailed. Customers would therefore be allowed to fail to comply with approximately 11 such requests before the penalties assessed would equal the annual interruptible discount. (D.86-12-091, at pp. 66-67.)

By Resolution E-3044 issued August 26, 1987, we altered these penalty provisions by authorizing PG&E to amend that penalty to provide that only three instances of noncompliance would cause the resulting penalties to equal the annual interruptible discount. This penalty approach was based on a set of graduated excess demand charges. Therefore, for the first failure to interrupt or curtail within twelve months the charge would be one-sixth of the annual incentive per kilowatt. For the second non-performance, the incremental charge would increase to one-third of the annual incentive with total charges assessed equaling one-half of that incentive. For the third and any subsequent non-performance, the incremental charge would be one-half of the annual incentive.

In authorizing this amendment to PG&E's interruptible penalty, we relied on the analysis of our Evaluation and Compliance (E&C) Division that this change would increase customer incentives to reduce load when requested. The change was found to also provide the utility with a high degree of reliability from these customers for load relief during emergency situations.

In this proceeding, issues similar to those raised with respect to PG&E's interruptible rate design have been presented. Specifically, we have before us the proposal by PSD to commence a new interruptible schedule based on marginal costs (I-6) and to close two previous schedules (I-3 and I-5) which are to be superseded by the new schedule. We find that PSD's proposed I-6 schedule, to which the majority of the parties have agreed in concept, achieves the goal of providing cost-based rates and in turn accurate price signals to interruptible customers. Certain modifications of this proposal, however, are required.

Specifically, we find the penalty for failure to interrupt as proposed by either PSD or Edison is too harsh and would act as a significant deterrent to customers moving to this schedule. As CMA has pointed out, the levels of the penalties recommended by these parties would essentially eliminate the discount upon a single failure to curtail with subsequent failures producing charges far in excess of firm rates.

While we find PSD's and Edison's proposals unduly harsh, Resolution E-3044 reflects that the opposite extreme of up to 11 failures to curtail or interrupt in a 12-month period is a too lenient penalty. As that resolution indicates, the result of such an approach is to reduce the customer's incentive to reduce load when requested. Since the goal of this schedule is to provide lower rates for less reliable service, we believe that reasonable penalties ensuring that the customer respond to requests to interrupt are essential. We find that the graduated approach for such penalties, adopted in Resolution E-3044, provides for such penalties.

We therefore find reasonable the inclusion of penalties for the new I-6 schedule similar to those adopted for PG&E in Resolution E-3044. Specifically, the penalties provided under the I-6 schedule for failure to respond to an Edison request to reduce load will be based on the same set of graduated excess demand charges adopted for PG&E in Resolution E-3044.

In this proceeding, we have again also been faced with existing interruptible schedules which require a specified contract term commitment and a new schedule which is based on marginal costs. As we concluded in D.86-12-091, we find that it is reasonable for the interruptible customers to expect consistency in rate design for the term of their contracts signed in response to that rate design. Additionally, CLECA/CSPG, IU, and CMA have raised valid arguments for maintaining the existing schedules for customers who have made investments in reliance on the availability of those schedules.

We are also concerned with Edison's assertion that PSD may not have considered the intent of Section 743 of the California Public Utilities Code in developing it proposed I-6 rate schedule. Section 743 specifically requires a utility to provide interruptible rates to steel producers and food processors lower than the utility's system average rate. The statute, with which we are required to comply, is designed to ensure a competitive level of incentives for these customers.

While we believe that these circumstances require that the I-3 and I-5 schedules remain open for a period of time, we do not wish to prolong service under these schedules at a time when an interruptible schedule based on marginal costs has also been made available to these customers. Our goal for charges incurred for interruptible service is the same as that for all other services -- cost-based rates.

For these reasons, we find that it is reasonable to leave the I-3 and I-5 schedules open for new customers until January, 1, 1991. At that time, Edison's next general rate case will have concluded, any "imperfections" in the I-6 schedule will have been resolved in that proceeding, and customers will have received three-years notice of the intended closing of these schedules. To ensure the communication of this notice, Edison's tariffs should specifically state that the I-3 and I-5 schedules will be closed to new customers after January 1, 1991.

For existing customers, we believe that it is reasonable for those customers who had signed a contract with Edison under the I-3 and I-5 schedules prior to the effective date of this decision to complete that contract term under those schedules. Therefore, the I-3 and I-5 schedules will be closed effective January 1, 1993, to this group of existing customers. For those new customers signing contracts under the I-3 and I-5 schedules between the date of this decision and January 1, 1991, the terms of their contracts should provide for their termination with respect to Schedules I-3 and I-5 no later than January 1, 1993, with the remainder of any unexpired contract commitment being served under Schedule I-6 after that time. Our goal in adopting this approach is to ensure that Edison can rely on the five-year interruptible commitment whether that commitment relates to Schedule I-3, I-5, or I-6. As recommended by PSD and Edison, Schedule I-2 should be closed and Schedule I-4 should be eliminated effective with this decision.

Finally, we address CLECA/CSPG's suggestion that current I-3 and I-5 customers be entitled to switch to the I-6 schedule at any time due to the cost-based nature of that schedule. The assurance provided by a contract commitment under the interruptible schedules is that Edison can estimate into the future the level of energy which will be available for Edison to respond to emergency situations. The specific schedule under which this commitment is made should not alter Edison's ability to rely on that load being available.

We therefore find reasonable CLECA/CSPG's recommendation which will also promote the use of the cost-based interruptible schedule, I-6. We will therefore direct Edison to include in its tariffs a provision permitting I-3 and I-5 customers to switch to the I-6 schedule at any time conditioned on the remaining term of its I-3 and I-5 contracts being completed under the I-6 schedule. The customer's change to the I-6 schedule should not result in the customer being billed the difference between the I-6 and I-3 or I-5 rates based on receipt of service under those schedules for part of the overall contract term.

Credits and penalties provided under Schedules I-1, I-2, I-3, and I-5 are not changed on an annual basis, but are recalculated to reflect a reduced number of on-peak hours resulting from the elimination of the on-peak period in the winter months. For Schedule I-5, however, the off-peak credit of $0.025/kWh applied to the off-peak floor rate of $0.05/kWh results in a $0.025/kWh rate, a rate which is less than the marginal energy cost. Rather than adopting a charge below the marginal energy cost, we will direct Edison to take the difference between the marginal energy cost and the off-peak rate and reduce the customer's bill by an amount equal to that difference.

With respect to the interruptible rates provided under Schedule I-6, we find that PSD's approach most accurately bases those rates on the value of interruptibility to Edison. It is necessary to adjust these rates, however, to reflect our adopted ERI value for Edison of 0.43. With this change in assumption, we otherwise find reasonable PSD's proposed methodology for calculating these rates. We also adopt the two super off-peak interruptible rate options to which Edison and PSD have agreed (TOU-8-SOP-1A and TOU-8-SOP-1B).

As we have noted CMA suggests that our adopted approach of basing interruptible rates on the value of such interruption to the utility fails to reflect the cost of serving the interruptible customer. CMA has acknowledged, however, that this issue was not sufficiently addressed in this proceeding to warrant a change in our approach. For Edison's next general rate case, however, we will direct Edison and PSD to develop an interruptible schedule based on cost of service to the interruptible customer, in addition to a schedule based on the current consideration of the value of interruptiblity to the utility. In this way, we will not only have the schedules to compare, but also the insights of the parties as to the merits of changing our approach for determining interruptible incentives to a cost of service basis.

d. Contract Rates

As we have stated previously, the Commission has concluded that special contracts or contract rates can serve as a means of mitigating uneconomic bypass. In this proceeding, Edison has proposed two contract rate options: the Incremental Sales Rate and the Self-Generation Deferral Rate. Edison believes that these options will enable it (1) to reduce its rates to levels which are closer to its marginal cost of providing service, in order to retain the loads of credible bypass candidates; (2) to provide cost-based price signals to promote new sales from customers with growing loads; and (3) to promote economic efficiency by permitting Edison to make better use of its existing generating capacity.

According to Edison, the Incremental Sales Rate, proposed schedule TOU-8-CR-1, consists of a high fixed charge and reduced demand and energy charges with the initial term of 5 years. The fixed payment would be based on a portion of the contribution to margin the customer would have made had they remained on the regular applicable rate.

Under the Self-Generation Deferral Rate, proposed schedule TOU-8-CR-2, a customer with self-generation potential would be charged the same costs which the customer would incur by self-generating. For those with an economic option to leave the system, Edison proposes to charge these customers the cost which the customer would incur acquiring the capacity and energy from another source. For the remaining customers, Edison would charge its costs of producing electricity in terms of total revenue requirement.

Edison believes that the Commission should adopt the Incremental Sales Rate in this proceeding and endorse the Self-Generation Deferral Contract Rate in concept for Edison's use beginning in 1988. Edison states, however, that implementation considerations for TOU-8-CR-2 should be deferred to the 3-Rs Rulemaking (R.86-10-001) in which contract guidelines are being considered.

PSD agrees with most aspects of Edison's proposal. PSD therefore urges the Commission's adoption of the Incremental Sales Rate in this proceeding with implementation considerations for the Self-Generation Deferral Rate deferred to R.86-10-001.

CMA states that consideration of both of Edison's special contract tariff proposals should be deferred and studied as part of the policy matters being considered by the Commission in the 3-Rs

Rulemaking, R.86-10-001. CMA points out that D.87-05-071 in that matter contemplates special contracts for large light and power customers under guidelines to be developed by the Commission in that proceeding. CMA believes that the Commission's actions on this subject should be consistent for all utilities.

We concur with CMA. We have made clear in D.87-05-071 that the guidelines and terms of special contracts and contract rates are to be examined and adopted in R.86-10-001. This effort will not only achieve consistency between utilities, but will also provide a single forum in which the appropriate responses to uneconomic bypass can be coordinated. In R.86-10-001, we will also be presented with the tools required to most efficiently achieve our goal of addressing uneconomic bypass. These tools will include contract guidelines proposed by all utilities and new forecasts of sales and revenue for the large power customer group which take into account regulatory revisions adopted in D.87-05-071.

As we have discussed in the Revenue Allocation portion of this order, the implementation of contract rate schedules requires more than the adoption of specific tariff terms. We must also be able to determine the level of revenue deficiency resulting from implementation of these schedules, and the manner in which that deficiency is to be allocated to customers. All of these concerns are best addressed in R.86-10-001 to ensure uniform and appropriate standards.

We therefore find that Edison's proposed generic special contract schedule, TOU-CR-2, should not be adopted in this proceeding. This proposal, however, does appear to be responsive to the bypass issue and would properly be presented in the context of R.86-10-001. We find, however, that it is appropriate to consider the design of Edison's proposed rate option, TOU-8-CR-1 in this rate case, but we will defer consideration of its revenue allocation effect to R.86-10-001. Therefore, we will authorize the TOU-8-CR-1 rate as part of Edison's tariff structure and direct that it be covered by ERAM until such time as a decision in R.86-10-001 separates Edison's customers into an ERAM and a non-ERAM group.

e. Standby Charges

In response to the needs of customers who have chosen to provide their own generation, Edison offers backup or "standby" service. This service is provided when the customer, for whom the installation of its own backup facilities would not be economic, requires utility service due to an outage at its generation facility.

In this proceeding, PSD has proposed a standby schedule to which Edison has agreed. The effect of this proposal would be to close current Edison Schedules SCG-1 through 3 and establish new Schedule S which would be available to standby customers along with new Schedule I-6. Edison does not agree, however, with PSD's additional suggestion to impose a "rate limiter" on standby charges. This proposal, as well as all other suggested "rate limiters," are discussed in a separate section below.

(1) Parties Positions

Under PSD's proposal, standby customers would contract for a certain level of standby service on any non-standby schedule. The customer would pay the applicable customer charge for that service schedule every month and the maximum demand charges for that schedule for the demand specified in their contract. If the standby customer takes service under the non-standby schedule, the maximum demand charge on the service taken would be waived up to the contract level.

In support of its proposal, PSD states that standby customers, like all other customers, should pay for services based on the costs Edison incurs in providing those services. In PSD's opinion, the costs for which standby customers should be responsible should therefore include those costs which they impose on the system even when no active demands are placed on the utility system. PSD states that such services include a meter, service drop, billing, and local distribution facilities sized to the maximum demand potential of the standby customer. With respect to this latter cost, PSD and Edison concur with the use of the full noncoincident demand costs, reflecting both marginal distribution costs and a portion of marginal transmission costs.

Edison has agreed with both PSD's proposed standby charges and terms as well as the principles supporting that proposal. PSD's approach, according to Edison, is required to ensure Edison of full recovery of distribution-related costs from customers with self-generation. Edison states that for a customer with both standby and supplemental loads, the combination of the standby and non-time related demand charges is intended to compensate Edison for its costs of serving both types of loads.

In the future, Edison also believes that a generation and transmission component may be appropriate to include in the determination of the standby charge in addition to the distribution component. Edison states that some consideration should also be given in the future to the equity of allowing a standby customer to be charged for replacement and backup service at average rates.

With respect to the interested parties, CMA, DGS, and the CSC all agree that standby rates should be cost-based. However, each has urged the Commission to consider means of mitigating rate shock in order to avoid discouraging customers from taking this service.

CMA therefore concurs with PSD's approach to calculating these rates and requiring a rate limiter. CMA also proposes that the same transitional phase-in be adopted for standby charges as has been proposed for domestic customers with respect to the move to a full EPMC revenue allocation.

To ensure that standby charges reflect the true costs imposed on the utility system by standby customers, DGS recommends that standby customers be charged for energy and demand when it is taken and that standby tariffs reflect the special characteristics of this service. Specifically, DGS supports the suggestions made by CMA during hearings in this proceeding (1) to permit all standby customers to select their own level of contract demand for standby service; (2) to phase-in standby rates; (3) to avoid imposing both a standby charge and a ratcheted maximum demand charge on standby customers; and (4) to reduce on-peak and mid-peak charges for regular service to standby customers in recognition of their lower coincidence demand. By adopting these recommendations, DGS asserts that the standby customer will be able to more effectively manage his own loads in response to accurate price signals.

The CSC generally supports PSD's proposed standby charge as modified by PSD's proposed rate limiter. The CSC disagrees, however, with Edison's and PSD's proposal to apply the standby charge against the standby load of all customers. The CSC asserts that customers that have paid for all facilities necessary for interconnection with Edison's transmission system must be exempt from the standby charge. According to the CSC, the goal of cost-based rates would not be achieved for standby customers if that customer's rates include equipment and construction costs associated with distribution or transmission facilities for which the customer has paid. Therefore, the CSC urges the waiver of the costs of these facilities in standby rates if they have been paid by the self-generating customer.

In its briefs, Edison responded to the recommendations of each of the interested parties. Specifically, Edison disagrees with the suggestion of CMA and DGS that standby charges should be phased-in in the same manner as the EPMC revenue allocation. Edison states that the impact of the increase proposed by Edison and PSD for standby charges on the total energy costs of the standby customer should be small. Even if the impact were greater, Edison states that there is no connection in this rate case between the substantial rate impacts for domestic customers which would result from the immediate move to EPMC revenue allocation and rate impacts for standby customers.

Edison also disagrees with CMA's and DGS's proposal that standby customers be allowed to select their own level of standby demand. According to Edison, this customer determination of standby demand would alter the current and better practice of this level being decided by Edison and the standby customer working together. Edison states that once this level has been determined and facilities have been installed, a commitment is made by both parties. To permit a customer to "back down" their standby demand level, according to Edison would be detrimental to other customers to whom the cost recovery of the "excess facilities" would be shifted, but who would receive no benefit from those facilities.

Edison also asserts that DGS's claim that Edison will collect excessive revenue from standby customers by levying both the ratcheted maximum demand charge and the standby charge is no longer valid. Specifically, Edison states that it has agreed with PSD to charge standby charges higher than it had originally proposed, but provide an exemption from the non-time related demand charges for the standby portion of a standby customer's load.

Edison states, contrary to the positions of CMA and DGS, that full on- and mid-peak demand charges should apply to standby customers. According to Edison, the charges which have been proposed properly focus on the total (standby plus supplemental) load which can be metered and billed. Therefore, Edison asserts that it is appropriate to view the loads of these customers collectively, even though if viewed separately these loads could appear to be random with little coincidence with system peak loads. Edison states that when viewed collectively the loads of the standby customers exhibit many of the characteristics of the TOU-8 customer group and require their being charged at the same rate level.

Edison also rejects DGS's suggestion that standby customers be charged for energy and demand when it is taken. According to Edison, noncoincident demand-related costs are a function of the level of facilities installed and do not fluctuate with the actual level of use by the customer. These costs should therefore be recovered through a standby charge applied to a fixed level of standby demand which reflects the level of facilities installed to serve the customer's standby load.

Finally, Edison states that it disagrees with the CSC's proposal that customers who have paid for all facilities necessary for interconnection with Edison's transmission system must be exempt from the standby charge. Edison believes that the extremely low standby charge is required to compensate Edison for interconnection costs still incurred by Edison, i.e., the costs of interconnecting these customers into the utility grid.

(2) Discussion

In D.86-12-091 we concluded for PG&E that charging standby customers the same rates as other customers was not discriminatory and would result in cost-based rates. We found that taken as a group, these customers had very little energy usage relative to the demand which they placed on the system. When these customers did take service, however, they imposed costs in the same manner as other large power customers with similar load characteristics. We found that for periods when service was not taken, it was appropriate to charge standby customers the cost of customer-related services and reserved facilities.

We find that the standby charges and terms to which PSD and Edison have agreed properly result in the uniform treatment of standby customers and other large power customers with similar load characteristics. PSD's standby proposal also effectively achieves the goal of providing cost-based rates and accurate price signals to customers who have chosen to self-generate and to those who are considering such a move. We believe that these charges properly take into consideration the load characteristics of the group as a whole and include fixed monthly charges needed to reflect the noncoincident demand of these customers.

The specificity in the cost to rate relationship sought by the interested parties appears to be aimed not so much at achieving cost-based rates as recognizing this customer group's "unique characteristics." We are certain that other TOU-8 customers can offer us instances in which their rates do not reflect their exact usage characteristics. While we have attempted to ensure rates that are cost-based and time-related, usage characteristics of the affected customer groups as a whole are an important consideration in ensuring that subsidization of the group by other customers does not result. To the extent that adverse bill impacts for these customers result from our adopted rate design, we find that PSD's rate limiter proposal for standby charges, discussed below, is a more appropriate means of adjusting these charges based on the standby customers' "unique characteristics."

In this regard, we note that the fact that a self-generator may have paid some costs associated with distribution and transmission facilities should not lead to the waiver of the standby charge which is based on <u>all</u> costs incurred by the utility to serve that customer. In the future, we suggest that Edison and PSD, however, continue to refine and clarify those costs are directly imposed on the system by the self-generator in receiving standby service. Edison, as stated previously, has in fact urged this course of action in asking that the Commission recognize the need for the inclusion of transmission and distribution components in the standby charge in the future.

Finally, we reject any request to "phase-in" standby charge increases. We fully concur with Edison that such a suggestion is appropriately reserved for such significant class rate impacts as will result to the domestic customer group from our move to an EPMC revenue allocation. As stated previously, the rate limiter proposed by PSD and discussed below is a more appropriate response to adverse bill impacts. We therefore adopt as reasonable PSD's standby rate proposal which requires the closing of Schedules SCG-1 through 3 and the establishment of Schedule S.

3. Rate Limiters

In this proceeding, three interested parties (FEA, CMA, and IU) have proposed that a "cap" be applied to the maximum effective change in TOU-8 customer bills to mitigate any adverse impacts caused by the adoption of cost-based rates for this customer group. PSD has also proposed a cap or "rate limiter" on its proposed standby charges. Edison opposes any cap on TOU-8 or standby rates.

a. Rate Limiter Proposals

FEA, CMA, and IU propose that to reduce the rate impact produced by the move toward cost-based rates a transitional "rate limiter" or maximum acceptable charge per kilowatt-hour should be adopted for the TOU-8 rate schedule. Customers whose average rate exceeds the limiter would be billed based on the limiter, rather than the filed tariff. CMA states that a phase-in of rate increases to the TOU-8 customer is required to afford that customer the opportunity to change its load patterns, based on long-standing price signals from Edison, in response to the new price signals which will result from this proceeding. CMA claims that based on PSD's and Edison's proposals, increases of between 20% and 151.1% could result for many TOU-8 customers, with one customer receiving an increase of 267.7%.

These parties also agree that the rate limiter adopted by the Commission for PG&E's large customer group in D.86-12-091 should serve as the model for the rate limiter to be considered in this proceeding. These parties cite the Commission's conclusion in that decision that the combination of cost-based rates and a rate limiter provide customers a clear signal of future bill increases while shielding those most severely impacted from the full immediate impact of the rate change.

FEA, IU, and CMA concur that the fact that none of these parties recommended a specific level for the cap or an estimate of the revenue impact should not be a reason for rejecting a rate limiter in this proceeding. IU states that the Commission was faced with the same situation in PG&E's proceeding but was still able to impose rate limiters. FEA asserts that the absence of a recommended cap relates directly to Edison's failure to provide customer impact data as PG&E had in its proceeding. Based on the absence of the necessary information, both parties recommend that Edison be directed to work with the Commission to develop an appropriate level for the rate limiter based on the actual revenue allocated and rate structures adopted in this proceeding for TOU-8 customers. CMA states that revenue deficiencies should be reallocated to the TOU-8 class as a whole.

PSD acknowledges that an inevitable consequence of moving to marginal cost based pricing is the potential for adverse bill impacts for some customers. PSD therefore does not oppose rate limiters like those adopted for PG&E's large power customers when the rate impact is beyond a reasonable level and affects a significant number of customers.

In fact, PSD proposed such a specific rate limiter for standby charges. PSD bases its limiter on the difference in on-peak usage between firm and standby customers. According to PSD, firm customers, by taking service continually, are likely to take service during actual hours of system peak. PSD states that in contrast, there is no assurance, but only a probability, that standby customers, taking only intermittent service will take service during any hours of actual system peak. PSD notes that standby customers are also capable of selecting a time of lowest cost incurrence for scheduled maintenance.

PSD has therefore proposed an "on-peak rate limiter" for standby charges to reflect the "probability" of standby customers taking service during the "on-peak" period. PSD states that it developed the limiter, which would be applied to adjust the on-peak charges otherwise applicable to a standby customer taking service, using a complex simulation model. While PSD notes that Edison has disagreed with its proposal, PSD states that Edison's witness did in fact acknowledge that standby customers should pay their "relative share of that on-peak capacity based on the probability that they may contribute to that on-peak load." (Tr. at p. 4211.)

DGS and the CSC both support the rate limiter proposed for standby customers by PSD. These parties concur in PSD's analysis that standby service is rarely required during the system's peak and that the rate limiter would reflect the utility's lower cost of supplying standby power.

Because the proposed increased in standby charges are dramatic, DGS also believes that a rate limiter is needed to avoid extreme rate impacts which would be unfair and might encourage uneconomic bypass. DGS therefore endorses both an on-peak and mid-peak rate limiter for standby customers.

The CSC believes that PSD's rate limiter is the "best effort" to develop a fair, cost-based charge for standby service. The CSC also states that Edison's rebuttal to the rate limiter focused on irrelevant and otherwise unsupported testimony that self-generators do not operate at high annual capacity factors. According to the CSC, annual capacity factors do not reflect a self-generators' capacity factors during peak hours.

In its brief, the CSC also proposed that a separate rate limiter be considered for standby customers purchasing under the I-6 interruptible schedule. Specifically, the CSC proposes the adoption of a rate limiter developed using the same methodology as

PSD applied to the standby rates, but also taking into account the 0.75 ERI associated with the I-6 schedule.

Edison rejects all of the rate limiter proposals made by PSD and the interested parties. Edison states that with respect to the proposals of IU, FEA, and CMA, none have included a specification of the cap or an estimation of the resulting revenue shortfall, the number of customers impacted, or the manner in which the revenue deficiency is to be recovered. Edison notes that only CMA proposed to set an upper limit on the revenue shortfall of 13 to 16% over the system average percentage change resulting from this proceeding.

Edison further believes that there is no need for a "cap" on TOU-8 rates since the impact of the rate changes has already been moderated by Edison's proposed rate design. Edison also believes that a rate limiter would permit a customer to impose loads during the summer on-peak period, but escape the resulting costs imposed on Edison's system.

Edison similarly objects to the application of rate limiters to standby customers. It is Edison's position that since the profiles of standby customers' loads, in the aggregate, are very similar to those of TOU-8 customers in the aggregate, they should be fully subject to all pricing terms and conditions of the TOU-8 schedule whenever these customers take service. Edison is again concerned with the potential of a resulting subsidy of this customer group by other customers.

Edison's greatest concerns, however, are reserved for individual rate limiters like those proposed by CMA and DGS. Edison believes that individually determined limiters would be extremely difficult and prohibitively expensive to administer.

b. <u>Discussion</u>

In D.86-12-091, we found for PG&E that, while our goal was to achieve cost-based rates, full implementation of such rates could result in severe bill impacts for some customers. We concluded that the best approach for mitigating adverse bill impacts involved adjustments to marginal cost-based demand and energy charges coupled with the use of rate limiters.

In D.86-12-091, for PG&E's mandatory large power schedule, E-20, we adopted a summer rate limiter for primary and secondary voltage customers of 1 cent/kWh above the average summer rate for the secondary voltage level. This rate limiter was found to have a 0.8% effect on industrial rates. We also adopted on-peak rate limiters based on the upper limit of the value of energy during the on-peak period at the coincident capacity cost plus the on-peak energy rate without capacity costs. (D.86-12-091, at pp. 58-59.)

In this proceeding, we similarly find that the rate limiter is an appropriate means of mitigating adverse bill impacts. By using the limiter, we are able to address this problem while still ensuring the adjustment of marginal cost-based rates which more accurately reflect the costs which the customer imposes on the utility system.

Only PSD, however, has provided us with a basis upon which to determine a specific rate limiter under any of Edison's large power schedules - in this case, for standby rates. Those parties urging the adoption of rate limiters for TOU-8 generally have, as Edison has noted, provided no formula from which the Commission could determine those limiters or the resulting revenue impact.

We agree with these parties that the level of the rate limiter is dependent on the revenue adopted. The overall revenue allocated to customer groups in this proceeding, however, is far less than that requested by Edison. Further, our adoption of an EPMC revenue allocation will result in substantial decreases to the large power customer group. We have also rejected Edison's and PSD's request for ratcheted demand charges which should mitigate the impact of those charges on seasonal customers when their demand on the system is low.

We recognize, however, that even under these circumstances, certain customers may still be adversely impacted by our rate design adopted for TOU-8. We therefore believe it is reasonable to adopt certain rate limiters aimed at mitigating adverse bill impacts at periods of peak demand. In determining these rate limiters, we will follow the approach taken in D.86-12-091 and adopt a summer rate limiter for primary and secondary voltage customers of 1 cent/kWh above the average summer rate for the TOU-8 secondary voltage level, excluding customer charges. The revenue deficiency resulting from the imposition of this rate limiter will be spread on an EPMC basis back to primary and secondary customers receiving service under TOU-8.

For on-peak rates for TOU-8 and standby customers, where applicable, we also find PSD's proposed on-peak rate limiter to be reasonable and well-supported in this record and will adopt rate limiters based on the value of energy during the on-peak period at the coincident capacity cost plus the on-peak energy cost, adjusted to EPMC. By using a rate limiter, we are able to adjust these rates in recognition of the unique characteristics of this group of customers, while continuing to ensure rates which more accurately reflect the cost of serving these customers. Revenue deficiencies resulting from the adoption of PSD's proposed on-peak rate limiter should similarly be spread on an EPMC basis back to all large power customers served under TOU-8, but these customers should pay no less than their customer cost.

No other limitations on standby rates, i.e., mid-peak rate limiters or interruptible rate limiters for standby customers, however, are required. The rate limiters which we have adopted for all TOU-8 customers coupled with the specific rate limiter proposed by PSD for standby customers should be sufficient to mitigate any adverse rate impacts resulting from our adopted standby rates.

E. Agricultural and Pumping Customer Group

1. Introduction

Agricultural rates are a continual focus of concern for this Commission. Over the years, the Commission has attempted to respond to the needs of this major California industry which is characterized by a significant electrical requirement and diversity in load patterns. Among the industries receiving electric service from Edison, agriculture represents one for which service options provide a key to economic stability.

In response to this need legislation was adopted in 1986 to require alternative service options for agricultural customers. Specifically, Section 744 of the California Public Utilities Code provides that all California electric utilities must offer tariffs to agricultural producers, where economically and technologically feasible, which provide "optional alternative interruptible service" and "optional off-peak demand service." The latter option is to include the availability of time-differentiating meters or other measurement devices. The criteria governing these tariffs is similarly provided in Section 744. Section 744 also states that the optional rates should not be less than the cost of serving these customers.

In D.87-04-028, the Commission considered a stipulation entered between PG&E, PSD, the Farm Bureau, and the Power Users Protection Council related to an agricultural TOU rate structure. This structure, which included a series of options for agricultural service, was adopted by the Commission with certain modifications.

In this proceeding, both PSD and Edison have presented comprehensive recommendations for modifying existing agricultural rate schedules and offering new options to these customers. While these two parties disagree on certain issues, their proposals reflect a joint effort to relate agricultural rates more closely to marginal costs. Both parties have also provided options designed to meet the requirements of Section 744. PSD states that while it does not disagree with the two options proposed by Edison, PSD believes that its proposal offers a much greater number of options (9) more fully reflecting the diverse operating patterns of agricultural customers.

The only party other than Edison and PSD which actually offered testimony and a brief on agricultural rate design was ACWA. ACWA's testimony and brief focus on the demand charges proposed by Edison and PSD for the PA-1 and PA-2 schedules and the need for an optional PA-TOU schedule for all water pumpers currently served under the TOU-8 schedule.

Concerns, however, were expressed by the Farm Bureau and the Citrus Growers Cooperative regarding certain aspects of the proposed agricultural rate structure.

These concerns focus on Edison's proposal to close its GS-1 schedule to new customers. These parties claim that this change will have a significant negative impact on citrus growers who have purchased existing wind machines with the expectation of continued service under the current GS-1 schedule. Additionally, the Citrus Growers Cooperative has asked that the off-peak credit provision of Schedule PA-1 (Special Condition No.5) be reworded to allow disconnecting of load during summer months only.

Although Edison believes that appropriate price signals must be provided to citrus growers who are considering the purchase of frost protection equipment, Edison also shares the concerns of these parties. Edison therefore recommends that these customers be placed on the proposed GS-TP schedule which will provide three additional years of service at rates similar to the current GS-1 rate. After that time, Edison states that these customers should be placed on Schedules PA-1 or PA-2 which provide cost-based rates. Edison also concurs with the change requested by the Citrus Growers Cooperative to Special Condition 5 of the PA-1 schedule.

We concur with Edison that the citrus growers should be offered an opportunity to respond to a change in rate design which could have an adverse effect on investments made in reliance on a prior rate structure. We find that Edison's suggested placement of citrus growers on the three-phase GS-TP schedule with movement to PA-1 or PA-2 after three years provides such an opportunity while moving these customers eventually to cost based rates. This change proposed by Edison along with the amendment of Special Condition 5 of PA-1 proposed by the citrus growers appropriately responds to the needs of these customers, and should be adopted. Since the load of most citrus growers exceeds 75 kW, we will direct Edison to reflect a special condition comparable to Special Condition 5 for PA-2.

In the following sections, we will review the parties' proposal first for changes to existing agricultural Schedules PA-1 and PA-2 and second for rate options for these customers. Within each of these sections, we will discuss each of the proposed rate structures and resolve the issues presented.

2. Schedules PA-1 and PA-2

Schedules PA-1 and PA-2 are the primary schedules specifically designed for agricultural customers. Schedule PA-1 is a flat rate energy schedule with a connected load charge based on the horsepower of the connected load. Schedule PA-2 is also currently a flat rate energy schedule, but provides a demand charge based on all kilowatts of billing demand, instead of a connected load charge.

For these rate schedules, as with those which we have previously discussed, Edison and PSD were able to reach substantial agreement on the appropriate rate structures. For PA-1, the parties are in complete agreement. Despite Edison's original proposal to close PA-1 to new customers, Edison subsequently agreed with PSD to keep this schedule open for three-phase agricultural customers. For PA-2, the only disagreement between the parties on rate structure involves the appropriate customer charge.

a. Customer Charge

Edison and PSD agree on setting the proposed PA-1 customer charge at $10 per month. For the PA-2 schedule, Edison has proposed a customer charge of $10 per month, while PSD has proposed a customer charge of $30.22 per month. Edison agrees with PSD that the PA-2 customer charge could and probably should be higher than the PA-1 customer charge based on the marginal customer costs for PA-2 customers being approximately twice that for PA-1 customers. Edison therefore states that it would not oppose a compromise of $20 per month for this schedule.

PSD bases its recommendation of a $30 customer charge on the need to reflect marginal customer costs. To this end, PSD states that its proposed customer charge would collect more than 50% of the marginal customer cost for PA-2 customers. PSD does not believe that Edison's proposed compromise, while recognizing the discrepancy in marginal customer costs between the two schedules, goes far enough in moving this charge toward a full marginal cost basis. PSD notes that by not reflecting these costs in the customer charge these costs will be recovered in a component (i.e., energy charges) unrelated to their causation.

We find that PSD's recommended customer charge is consistent with our policy to recover fixed cost components in fixed charges, with those charges based on marginal costs. The impact of a three-fold increase in a customer charge could, however, have the effect of causing customer confusion regarding the need for such a significant increase in a fixed cost. We would also be offering little notice or opportunity for the PA-2 customer to respond to this change.

We therefore find reasonable and adopt Edison's proposed compromise of a $20 per month customer charge for the PA-2 schedule. This charge will reflect the difference between marginal customer costs between the PA-1 and PA-2 schedules and will move the PA-2 schedule closer to its marginal customer cost responsibility. These results will also be achieved without as significant an adverse impact as the charge proposed by PSD.

b. Demand Charge

Edison and PSD agree on setting the PA-1 connect charge at $2 per HP. The parties also agree on setting the proposed PA-2 time-related demand charge at $6.00 per kW in the summer with no charge in the winter. The non-time related demand charge would be set at $2.30 per kW of the current billing period demand or 50% of the highest demand over the previous 11 months whichever is greater.

ACWA opposes the noncoincident demand charges at the levels proposed by either Edison or PSD. According to ACWA, the revenues which would have been collected by the noncoincident demand charges should be collected through on-peak demand charges.

If the Commission determines that noncoincident demand charges are appropriate, ACWA asks that these charges be set at half the level proposed by Edison and PSD to account for longer-lived rural distribution equipment. ACWA asserts that it is inappropriate to assess a noncoincident demand charge at system average marginal cost because rural lines are sized for a lower coincidence factor than urban lines. According to ACWA, the Edison and PSD rate designs also wrongly presume that the amount of electrical diversity on rural lines is identical to heavily-industrialized urban lines.

As a first item in addressing the demand charges proposed by Edison and PSD, we reference our previous finding in this decision that "ratchets," which act to maintain demand charges at a constant level even during periods of low load, are not to be used in calculating demand charges. This conclusion, the reasoning for which is reviewed at greater length in our discussion of demand charges for the TOU-8 schedule, is equally applicable to the agricultural Schedule PA-2.

While our goal is to reflect fixed costs in fixed charges, we also wish to ensure that the fixed costs being included in those charges relate in fact to the costs which the customer imposes on the system. We find that agricultural customers do impose noncoincident demand costs on the system and should be charged rates in accordance with those costs. We further find, however, that ACWA's testimony has demonstrated that PSD's and Edison's proposed noncoincident demand charges reflect costs imposed by urban customers, rather than the rural customers for whom the agricultural schedules have been developed.

For this reason, we will adopt ACWA's proposal to reduce PSD's and Edison's proposed noncoincident demand charges for PA-2 by one-half, with a similar reduction, for purposes of consistency, in their proposed PA-1 connect charge. As these costs are unrelated to time-related demand, as ACWA's position suggests, it would, however, be inappropriate for them to be reflected in on-peak demand charges as ACWA has recommended.

With the exception of these changes, we otherwise find reasonable the demand charges proposed by Edison and PSD. Those charges, as modified above, should therefore be adopted.

c. Energy Charge

Edison and PSD agree that there should be no seasonal differentiation of the PA-1 and PA-2 energy charges. PA-1 energy charges are proposed by these parties to be set residually to collect the revenue requirement not collected through the customer or connection charges. The PA-2 energy rate is proposed to be a blocked energy rate set at 5.0 cents/kWh for all kWh in excess of 300 kWh/kW. The first block energy rate is proposed to be set to collect the remaining revenue requirement not recovered through the other rate components.

We find reasonable the energy charges for the PA-1 and PA-2 schedules proposed by Edison and PSD. These charges, based on sound rate design principles, were not challenged by any other party and should be adopted.

3. Agricultural Rate Options

Agricultural rate options have been proposed by three parties in this proceeding: Edison, as described in its Supplemental Exhibit on Agricultural Rate Options (Ex.165), PSD, as presented in its original rate design exhibit (Ex. 61), and ACWA, as included in Exhibit 96. These proposals are summarized below followed by our resolution of the issues presented.

a. Parties Positions

Edison states that its proposed agricultural rate options are similar to those proposed by PSD. These options include an on-peak time period option (existing Schedule TOU-PA-2 with a six-hour or a four-hour summer on-peak period) and a three-day option (proposed Schedule TOU-PA-3D with a split week option providing rate differentials for three consecutive days (Monday through Wednesday or Wednesday through Friday)). Edison states that these options differ from PSD's proposals in that the options do not include a qualifying criteria of 35 kW for demand metered options, and do permit large customers (above 35 kW) to choose the connect load basis TOU option.

Edison states that it has also proposed an interruptible option which would be available to all agricultural and pumping customers. According to Edison, this option would not only provide some measure of dispatchable load, but would also permit Edison to retain existing sales which might otherwise be lost through conversion to diesel pumping. Edison states that these objectives can only be accomplished, however, if the proposed level of credit (1.5 cents/kWh) is permitted.

Edison states that its proposed options for agricultural customers were developed jointly with a working group of farmers representing all agricultural areas within Edison's service territory. In contrast, Edison believes that PSD's proposed options merely represent a "carry-over" from the PG&E general rate case and were not designed to meet the requirements of Edison's agricultural customers. Edison also believes that PSD's proposed options are much more restrictive than those proposed by Edison, especially with regard to smaller customers.

PSD states that it has no criticism of Edison's time-of-use proposals which, as Edison has noted, almost completely conform with two of PSD's proposed options. PSD's only objection is Edison providing a demand charge for TOU-PA-2 which differs from the level set for PA-2. PSD asserts that demand charges should be the same for these two rate schedules which reflect similar size and cost causation characteristics.

PSD' states that its primary objection to Edison's proposal is that it does not offer a sufficient number of options. PSD states that it has proposed nine schedules, including a super off-peak rate option for agricultural customers. Each of these schedules has three components -- customer charges, demand charges and energy rates -- developed consistent with overall PSD rate design policies.

PSD states that eight options relate to four basic schedules which are offered separately to customers with demands less than 35 kW and those with demands greater than 35 kW. These schedules include the following:

1. TOU-PA: a standard TOU schedule.

2. TOU-PA (SPLIT WEEK): for agricultural customers who need a continual pumping run to irrigate crops and are extremely limited by or cannot operate outside TOU peak periods.

3. TOU-PA (REDUCED PEAK HOURS): For customers who must irrigate during daylight hours, but can choose shorter peak periods to suit their operations while shifting peak use among hours of the peak period.

4. TOU-PA (MINIMUM BILL): developed in response to evidence from Edison and growers that system bypass with diesel engine pumping may be economic for high load factor customers with the current average electric rates.

PSD states that its ninth option is the super off-peak rate, TOU-PA-SOP. This schedule is proposed to be based on TOU-8-SOP, but with a simpler structure for agricultural customers.

PSD states that its basis for providing separate sets of schedules for agricultural customers corresponding to their demand level relates to the need to ensure that connected load based schedules are made available only to customers below 35 kW. PSD notes that the Edison witness acknowledged the correctness of PSD's assumption, on which its differentiation in schedules is based. This assumption is that PA-1 and PA-2 customers can be distinguished by the level of their demand, with the demand of PA-2 customer exceeding 35 kW and the demand of PA-1 customers being less than 35 kW.

PSD also responded to Edison's criticism that its recommendations are merely a "carry over" from those adopted for PG&E's agricultural customers. PSD states that while it used the same considerations raised in the PG&E proceeding in developing its agricultural rate options for Edison, the options were in fact tailored to meet the needs of Edison's customers.

In its Exhibit 96, ACWA urged the Commission to adopt a PA-TOU schedule which would be optional for all water pumpers currently served under the TOU-8 rate schedule. According to ACWA, PA-TOU would be identical to TOU-8 in its base, but would permit selection of a narrower on-peak period with a higher demand cost commensurate with the greater coincidence with system peak. PA-TOU would, in ACWA's opinion, offer a realistic opportunity for water pumpers to respond to TOU rates.

Specifically, ACWA's proposed PA-TOU would permit the water pumper to choose 2, 3, 4, or 5 hours on-peak as an alternative to the full 6-hour (12:00 p.m. to 6:00 p.m.) period. ACWA states that PA-TOU would differ from other Edison service reliability options in that the penalty (on-peak) period would not last as long as a curtailable or interruptible period. The shorter period is necessary, according to ACWA, due to the inordinately high cost of additional storage, mains, and pumps.

With respect to the agricultural rate options proposed by Edison and PSD, ACWA states that the menu of agricultural rates proposed by Edison in Exhibit 165 is not as comprehensive as that adopted in D.87-04-028 for PG&E. ACWA therefore supports PSD's proposed options which ACWA finds comparable to those adopted for PG&E.

b. Discussion

As we have indicated previously in this order, our reliance in this proceeding on recent rate decisions of other utilities is largely due to the need to ensure the application of consistent rate design policies to all utilities which we regulate. We assure Edison and its agricultural customers, however, that the specific needs of Edison's customers, to the extent that they differ from that of customers within another utility's service territory, are considered in the rate design which we adopt.

In this case, PSD has responded to our most recent rate design policy applied to agricultural rates. That policy, reflected in D.87-04-028, is to provide greater control to agricultural customers over their energy usage and costs consistent with the needs and usage characteristics of those customers and the statutory mandate of Section 744. We find that PSD's proposal meets and exceeds the minimum requirements of that statute.

We find therefore that the PSD proposal, which includes the options recommended by Edison, as well as several more options for agricultural customers is reasonable and should be adopted. We also believe that PSD has provided a reasonable basis for distinguishing between customers based on their demand level being in excess of or less than 35 kW. This distinction is based on and appears to be reflected in the demand levels of customers choosing either the PA-1 (less than 35 kW) or PA-2 (above 35 kW) schedules. Edison, however, should be afforded a reasonable period of time to inform its agricultural and pumping customers of this distinction based on connected load and to install the required metering. These tariff options should therefore be implemented no later than June 1, 1988.

With respect to ACWA's proposed PA-TOU schedule, in D.87-04-028 we found that agricultural TOU rate options appeared reasonable for some ACWA accounts. We wish to ensure in this proceeding, as we did for PG&E, however, that service under these schedules is reserved for purposes related to agriculture. We will therefore apply the same criteria adopted in D.87-04-028 that service under this type of schedule be limited to customers for whom at least 70% of the water pumped by an individual account is for agricultural purposes

We therefore find reasonable the mandatory transfer of ACWA accounts and other large pumping accounts which meet this standard from TOU-8 to the agricultural class. Under these circumstances, such customers will be able to take advantage of the adopted TOU-PA Reduced Peak Hours schedule which we believe addresses the need of agricultural water pumpers for a service option based on narrower time periods than are currently available under TOU-8. It is therefore unnecessary to adopt the PA-TOU option proposed by ACWA.

In evaluating the proposed rate design for the agricultural class, we note the significant contribution made by the members of PSD and the employees of Edison who developed and substantiated creative and responsive rate options where none existed before. Specifically, we find these adopted schedules to be fully in accord with the purpose of Public Utilities Code Section 744. This section requires time-differentiated off-peak rates to allow an agricultural producer the opportunity to utilize cheaper off-peak electricity. By designing and substantiating a three-part schedule, PSD has provided an even greater opportunity for agricultural producers to lower their energy costs.

Indeed, we were disappointed in the area of agricultural rate design that there was not more active participation and information from the agricultural community itself during this proceeding. By law we cannot extend rates to any class unless those rates have been shown to be just and reasonable in the context of the individual class and the whole body of ratepayers. In this case, we believe that we have made substantial strides in implementing a responsive agricultural rate design. Because of lack of involvement by the agricultural ratepayers themselves, however, we are concerned with communicating the provisions and money-saving potential of these rates to agricultural ratepayers and assuring proper mitigation of detrimental impacts.

Consequently, we find that efforts must be made to reach out directly to this class of ratepayers and actively solicit input from this group. Edison is therefore directed to convene workshops, the purpose of which will be to explain the reasoning behind the new agricultural rate design and solicit input from ratepayers in this class on possible ways to "fine-tune" these rates. PSD (now called Division of Ratepayer Advocates) should also participate. We note that there will be no reallocation of revenues as a result of these workshops. We anticipate, however, that modification to the present rates will occur that will maximize the opportunity for agricultural ratepayers to lower their individual rates consistent with our philosophy of marginal cost pricing.

F. Street and Area Lighting Customer Group

1. Introduction

Several of the issues which have been raised with respect to streetlighting by Edison, PSD, and CAL-SLA have been previously addressed in this decision. These issues include our decision to include marginal customer costs and energy charges associated with streetlighting in the revenue allocation process. In this portion of our decision, we will focus on the specific recommendations made by Edison, PSD, and CAL-SLA with respect to the street and area lighting schedules LS-1 (Edison-owned street lamps), LS-2 (customer-owned street lamps), LS-3 (metered streetlight service), OL-1 (outdoor lighting), and DWL (domestic walkway).

Before we consider those issues, we note that PSD has expressed concern regarding the amount of time and effort devoted to streetlighting issues when only one characteristic distinguishes this class from other customer groups. That characteristic, according to PSD, is that certain customers in the streetlighting class rent their streetlights from Edison. PSD believes that this characteristic does not justify a totally different rate design approach than that applied to other customer groups. PSD asserts that the same basic, sound economic principles which guide the rate structures of other schedules should therefore be applied to the rate design adopted for streetlighting.

With this last statement, we agree. While the usage characteristics and other unique features of streetlighting customers should be considered in rate design, recognition of those characteristics do not require a wholesale departure from our adopted rate design philosophy. We believe that these customers can benefit from and should be charged rates which reflect the costs which these customers impose on the utility system. Our inclusion of streetlighting, with respect to the energy component of streetlight charges, and streetlighting marginal customer costs in the revenue allocation process are a recognition that these customers, despite unique traits, also share characteristics common to all other Edison customers.

As a frame of reference for our analysis of the various streetlighting issues, we also wish to note that in Edison's last general rate case (D.84-12-068), we directed Edison for this proceeding to undertake a current cost of service study for streetlighting. Additionally, Edison was to provide alternative rate designs for streetlighting reflecting the "additive" and the "unbundled" approaches. The "additive" approach to rate design essentially requires each of the cost components of the total rate for the streetlight schedules to be identified. With these tools, the Commission concluded that revisions to the streetlighting schedules could be undertaken. We note that in this proceeding Edison has responded to both of these orders which are in keeping with our goal of providing cost-based, unbundled rates.

2. Cost of Service Study

CAL-SLA asserts that Edison's cost of service study for streetlighting fails to comply with D.86-12-068. CAL-SLA believes that Edison has interpreted the Commission's mandate to perform a historical cost analysis as permission to undertake a Reproduction Costs New analysis. CAL-SLA asserts that the proper approach would have been to reflect an Original Cost Less Depreciation (OCLD) analysis.

Edison objects to CAL-SLA's criticism of its cost study as unfounded. Edison states that it in fact performed its study the only way possible with the data currently available. Additionally, Edison cites page 370 of D.84-12-068 as requiring that the cost of service study for the streetlighting customer class be based on historical costs, if adequate records were available, or "build up" costs.

Edison states that its asset accounts, in keeping with the FERC Uniform System of Accounts, include none that are exclusively for streetlights and do not contain any reserve for depreciation as implied by CAL-SLA. Edison also notes that a OCLD figure is not readily available to Edison.

We find that Edison's cost of service study is in keeping with our directives in D.84-12-068. A Replacement Cost New methodology was an appropriate basis on which to develop that study.

3. Energy and Demand Charges

In this proceeding, Edison states that it has responded to the directives of D.84-12-068 by proposing rate levels and rate design for streetlighting based on a cost of service analysis and reliance on both the additive and unbundled rate design approaches. Edison believes that the development by PSD and CAL-SLA of energy and demand rates for streetlights based on an EPMC allocation is contrary to the Commission's directives in D.84-12-068 which excluded streetlighting from the marginal cost revenue allocation process.

In calculating energy and demand charges for streetlights, Edison states that it based these rates on a weighted average TOU-GS rate. In addition to the weighted average TOU-GS rate, $2,500,000 of unallocated costs were spread on an equal-cents-per kWh basis for all street and area lighting customers. Edison states that its reliance of the TOU-GS rate is based on the reasoning that, if streetlight rates were eliminated, the streetlight customer would most likely be served under a general service tariff along with other customers of similar size and load shapes. According to Edison, the TOU-GS schedule seemed to be the most likely general service tariff under which streetlighting customers would be served under these circumstances due to the primarily off-peak usage of streetlights.

Edison questions the results of the PSD and CAL-SLA proposals which cut existing energy rates in half for all customers in the streetlight group in the face of rate increases to all other classes. Edison believes that there should be some relationship between the rates charged for streetlighting and those charged others for similar service (i.e., TOU-GS).

As noted by Edison, PSD and CAL-SLA advocate establishing energy charges for streetlighting on an EPMC basis. PSD recommends that an additional 5% of the developed rate be added to reflect miscellaneous streetlight costs identified by Edison. PSD believes that the EPMC approach which it advocates provides the proper price signals for streetlight customers and ensures uniformity in the rate design principles applied to all of Edison's customers.

PSD believes that Edison's reliance on the TOU-GS schedule as the basis for its streetlighting rate is unjustified. Edison's arguments regarding the size similarities between the streetlight and TOU-GS customer are, according to PSD, invalid. PSD asserts that the only specific link found by Edison between these two types of customers was that the average size of a streetlight customer was around 300 lamps. PSD states that the fallacy of Edison's logic can be seen in assuming that a customer with 3,000 streetlights would be analogous to a TOU-8 customer, while one with 10 streetlights would be analogous to a domestic customer.

PSD asserts that in fact Edison has provided no basis for asserting that the costs imposed on its system by a streetlight customer bear any relation to those imposed by a TOU-GS customer. Further, PSD states that there is absolutely no similarity between the load profile of these two customer types. The determination of load profile requires, in PSD's opinion, an examination of the profile of the entire class which for TOU-GS would include extensive on-peak usage that is absent from the load profile of streetlight customers. For the streetlight customer, PSD cites the testimony of Edison's own witness that streetlights are characterized "by a uniform load curve, the bulk of which is in the off-peak and mid-peak areas with a small portion in the on-peak area." (Tr. at p. 4019.)

CAL-SLA concurs with PSD's assertion that the evidence does not support Edison's proposed energy charge. Like PSD, CAL-SLA questions Edison's reliance on a schedule (TOU-GS) which includes customers whose load in no way reflects the usage characteristics of the streetlight customer group. If TOU-GS is to be used, CAL-SLA questions why the TOU-GS-SOP (super off peak) rate was not selected since such a rate schedule would be more consistent with the usage patterns of a streetlight customer.

CAL-SLA also questions Edison's proposal to allocate $2.5 million on an equal cents per kilowatt-hour basis to the streetlight class as a whole and not to the specific schedules to which these costs can be attributed. CAL-SLA further asserts that Edison has failed to present the complete factual data necessary for a showing to justify the inclusion of these unallocated charges in rates.

We concur with PSD's and CAL-SLA's recommendation that streetlight energy and demand charges should be based on marginal costs. This approach is consistent not only with the rate design policy applied to all other Edison customers but also with our decision in this proceeding to include streetlighting in our marginal cost revenue allocation process. The recommendations of PSD and CAL-SLA therefore mirror our effort to bring the design of streetlight rates into the "mainstream."

The value of a marginal cost-based approach to rate design and revenue allocation as a means of providing cost-based rates and accurate price signals has been repeated numerous times in this decision and is equally applicable to the streetlight customer. The fact that this approach might yield rates which are substantially less than that of another customer group of similar size should not lead to artificially imposing that schedule on streetlights. We agree with PSD and CAL-SLA that Edison's reliance on the TOU-GS schedule to calculate energy charges for streetlights is misplaced and is a significant departure from our polices emphasizing rates based on customer-imposed costs and use characteristics.

We therefore find reasonable PSD's proposed demand and energy charges for the street and area lighting customer group.

These charges include the addition of 5% of the developed rate to the final rates to reflect miscellaneous costs identified by Edison. The further inclusion of the unallocated $2.5 million identified by Edison is therefore unnecessary.

4. Customer Charge

Edison states that, based on its cost of service study, it properly included a minimum distribution system charge to streetlight rates to reflect the hook-up cost of streetlight customers. Edison further asserts that its customer charge for LS-3 metered service of $11.00 per meter per month, which was challenged by CAL-SLA, is reasonable and relies on the same methodology which Edison used in calculating the customer charges for series customers which were not opposed by CAL-SLA.

PSD disputes Edison's imposition of a MDS charge. PSD states that PSD's marginal customer cost approach (TSM) meets all of the criteria for establishing cost-based streetlighting rates and eliminates the necessity of an additional MDS charge.

CAL-SLA also disputes Edison imposition of an MDS charge. CAL-SLA states that no reason has been furnished by Edison to impose this charge in lieu of or in addition to PSD's TSM approach. CAL-SLA also recommends that customer charges be determined at a flat rate.

As this decision reflects, we have previously adopted PSD's TSM approach for determining marginal customer costs and have included in the revenue allocation process marginal customer costs for streetlighting developed on that basis. Having reflected marginal customer costs in revenues allocated to the streetlighting customer class, it is no longer necessary to include an MDS charge, as suggested by Edison, in streetlight rates. Edison's proposal is therefore rejected.

With respect to the determination of customer charges, we are concerned with CAL-SLA's suggestion that these charges be determined on a "flat rate" basis, when for other aspects of the streetlight rate structure CAL-SLA has supported marginal-cost based rates. In keeping with our adherence to marginal cost principles, we concur with PSD that the customer charges for this group should be based on the same methodology (marginal customer costs) applied to all other customer groups. We therefore adopt PSD's proposed customer charges for streetlighting.

5. Facilities Charges

Both Edison and PSD have concluded that the appropriate methodology for calculating streetlight facilities charges is a Reproduction Cost New with an Economic Carrying Charge analysis. In contrast, CAL-SLA believes these charges should be based on Original Cost Less Depreciation to set the revenue requirement and Reproduction Cost New Less Depreciation for revenue allocation.

PSD and Edison have proposed almost identical facilities charges for streetlighting, except for PSD counting part of the Regulating Output or "RO" transformer as a facilities charge, an approach which we have previously adopted. Both parties have also agreed on a charge of $1.00 per lamp per year for the transformer charge on Edison-owned lamps.

PSD and Edison advocate pricing streetlight facilities based on a marginal cost approach. PSD states that this approach provides the proper price signals and approximates the long-run rental cost of providing streetlighting facilities to customers. PSD challenges CAL-SLA's approach which it states is not based on marginal costs and would not provide the proper price signals.

PSD also notes that its facilities charges were not scaled upwards to reflect their contribution to overall revenue requirement, as Edison has claimed. Rather, according to PSD, the facilities charges proposed by both itself and Edison are priced at full marginal cost.

We find that PSD and Edison have followed the correct approach to calculating streetlight facilities charges -- one based on the cost of those facilities at the margin. The parties have also appropriately used a Reproduction Cost New approach. This approach, consistent with that used by Edison in developing its cost of service study, provides a reasonable basis upon which to develop the facilities charge. Edison has made clear that its accounts do not include an OCLD figure for streetlights and has correctly stated that the Commission has permitted Edison to rely on "build up" costs in the absence of reliable historical data. Edison has shown that an embedded cost of service study would be an expensive undertaking which would necessarily be borne by the streetlight customers.

We find no necessity of imposing such additional costs on these customers when the approach used by Edison in developing its cost of service study and by Edison and PSD in developing facilities charges is reasonable and should serve as the basis upon which to determine streetlight facilities charges. We therefore adopt PSD's facilities charges, which reflect our approval of the partial inclusion of the RO transformer in those charges.

6. <u>Streetlight Rate Design</u>

As stated previously, Edison responded in this proceeding to the Commission's directive in D.84-12-068 to provide alternative rate designs for streetlighting based on the "additive" and "unbundled" approaches. Edison states that its rate design is therefor based on the "unbundled" method where individual cost components were identified and aggregated to a total rate (an "additive" rate form). According to Edison, this rate structure uses a marginal cost-based rate design, recognizes marginal customer costs, and sends appropriate price signals to customers. In order to simplify the streetlighting tariffs and promote customer understanding, Edison has incorporated the existing Schedule LS-4 into the rate structure of Schedules LS-2 and LS-3, thereby eliminating the LS-4 schedule. Schedules LS-2 has also been revised to allow easier comparison to Schedule LS-1.

Despite this showing, CAL-SLA claims that Edison has failed to provide unbundled charges in its tariff sheets that are easily understood. CAL-SLA states that a review of Edison's tariff sheets reveals that charges are not listed as energy, customer, maintenance, and facilities, as CAL-SLA has consistently proposed. Unless the charges are separated as in this manner, CAL-SLA states that streetlight customers will not be able to determine which schedule to choose. CAL-SLA therefore requests that the Commission order Edison to prepare tariff sheets which provide for a clear distinction between energy, customer, maintenance, and facilities charges based upon a common denominator (i.e., per lamp per month basis).

In contrast, PSD states that it has reviewed and accepted Edison's "unbundled" rate design and "additive" rate form which it finds consistent with and directly responsive to Ordering Paragraph 11 of D.84-12-068. PSD states that offering a completely "unbundled" rate structure as proposed by CAL-SLA would be difficult to administer.

Edison also disputes CAL-SLA's assertion that its tariff sheets provide no division of major cost components. Edison believes that CAL-SLA has failed to recognize the distinction between unbundled charges for rate design and the information which is provided on a tariff sheet.

Edison states that its tariffs clearly identify the following charges: energy, series service power factor, relamping, and facilities and maintenance charges. The "other charges" to which CAL-SLA refers are, according to Edison, fixed facilities and their related maintenance and customer billing charges. Edison states that since a customer never maintains Edison facilities, it is not necessary to show the maintenance separate from the facility charge. Further, if a customer wants to examine the fully unbundled costs of streetlights, Edison states that it will provide the customer work sheets which in detail show all cost components.

Edison notes that if it were to provide fully unbundled tariffs there would be thirty times more information required in its tariff sheets, a result which Edison states would hardly promote customer understanding.

We concur with Edison and PSD that Edison has complied with our order in D.84-12-068 in developing its rate structure for streetlighting. A review of Edison's tariffs reveals that these tariffs do reflect "unbundled" rates. The level of detail requested by CAL-SLA was not intended by our last order, and we question, like Edison, whether such detail would in fact heighten customer understanding. Given the amount of time and expense which would no doubt be required to develop and explain such a tariff, we do not believe that such costs are justified or that the streetlight class would significantly benefit from those changes.

We therefore find reasonable and adopt Edison's proposed rate design for streetlighting. For Edison's next general rate case, Edison should, however, consider what detail could be added to the tariff which would enhance customer understanding.

7. <u>Rate Limiter</u>

CAL-SLA states that for many lamp-types, Edison's rate proposal results in significant rate increases over present levels. CAL-SLA states that any such rate increase is unfair given Edison's requested increase in revenue of 5.3% as compared to the increases for certain lamp type which will range from 12% to 91% per lamp. CAL-SLA therefore recommends that a 5% cap be placed on any rate increase for streetlighting with no cap being placed on rate decreases.

For streetlight rates, Edison states that it has no objection in concept to a rate cap provided that cap is functional, fair to all customers, and applicable to both rate increases and decreases. Edison notes, however, that while individual lamps may have increases up to 130% or decreases up to 50%, any given customer may have no net change or very little change based on the customers' mix of lamps.

PSD disputes the need for rate limiters for streetlighting rates. Like Edison, PSD states that for most streetlight customers, little or no net change in rates will be experienced based on the customer's mix of lamps.

For the large power customer group, we have adopted rate limiters on-peak period charges designed to mitigate adverse rate impacts resulting from our adopted rate structures for the TOU-8 and standby rate schedules. In the case of streetlights, usage is almost entirely off-peak permitting these customers to take advantage of lower rates in the first place. The unique usage characteristics of streetlight customers, in this instance, therefore, does not require that a mechanism designed for customers faced with substantially different circumstances be extended to the streetlight class. We also find that the record reflects that the customer's mix of lamps will largely offset that customer being faced with any of the significant increases attributable to one particular lamp type. For these reasons, we reject CAL-SLA's request for a rate limiter on streetlight rates.

8. Miscellaneous Issues

Edison, PSD, and CAL-SLA agreed on a number of miscellaneous issues. Among them PSD and CAL-SLA agreed on (1) the load shape used by Edison in determining the time-of-use characteristics of this class, (2) the refined series kWh losses calculated by Edison for use in calculating energy consumption for LS-2 series customers, (3) the series KVAR losses calculated by Edison and the "Series Service Power Factor Charge" of $0.30 per KVAR demand, and (4) the weighted average pole charge developed by Edison for inclusion in the LS-1 lamp-related charges. We find that these proposed charges and rate structures are reasonable and should be adopted.

In the following sections, we will review issues which remain in dispute. These issues were principally addressed by CAL-SLA and Edison.

a. Customer Account Expense

Edison and PSD have agreed to a customer account expense of $.12058 per lamp per month. CAL-SLA has proposed a charge of $0.22 per lamp per month based on Edison's average cost study.

In designing its rates for streetlighting, Edison states that it has developed all charges on a marginal cost basis. Edison therefore disputes CAL-SLA's reliance on Edison's average cost study which would improperly mix the results of that study with a marginal cost-based rate design.

We concur with Edison that, for consistency in the methodology used to calculate structure rates, it is appropriate to rely on marginal costs to develop the customer account expense. We therefore find reasonable and adopt a customer account expense of $0.12058 per lamp per month as Edison and PSD have agreed.

b. Domestic Walkway Lighting (DWL) Rates

CAL-SLA has questioned Edison's proposed cable and photocontroller charge for customer-owned systems on Schedule DWL. Edison states that since CAL-SLA proposes no alternate rate or solution, their simple lack of understanding of the rate negotiated on special contracts is not sufficient to eliminate the charge. We concur with Edison and will adopt its proposed cable and photocontroller charges for the DWL schedule.

c. Proposed Special Conditions

CAL-SLA asserts that Edison's proposed Special Condition 2 relating to the installation of LS-2 and LS-3 streetlights does not reflect present circumstances. CAL-SLA has therefore proposed its own version of Special Condition 2. According to CAL-SLA, its proposal is consistent with the current arrangement of installing

LS-2 and LS-3 streetlights with the locations decided on a case-by-case basis between local government, land developer, and the utility.

We find that CAL-SLA has justified its proposed change to Special Condition 2, contrary to Edison's statements that no reason was offered for that change. In keeping with current installation practices, Special Condition 2 should therefore reflect the language proposed by CAL-SLA.

CAL-SLA additionally recommends that Edison's proposed Special Condition 10 of Schedule LS-2 relating to kilowatt-hours be amended to reflect the lamp loads and kWh estimates for HPSV and LPSV lamps recommended by CAL-SLA. CAL-SLA notes that for PG&E the Commission agreed with CAL-SLA that the manufacturer's specifications should be used for determining energy usage of streetlights (D.86-12-091, at pages 90-91). In that proceeding, CAL-SLA notes that the Commission specifically rejected PG&E's contention that the manufacturer's specifications should be modified to include a 3% line loss factor.

CAL-SLA states that its review of manufacturer's specifications for lamp loads does not show a 3% loss. CAL-SLA therefore recommends that Special Condition 12 of proposed Schedule LS-2 be amended to exclude the alleged 3% line loss factor.

Edison states that in making these recommendations, CAL-SLA has ignored actual field operations affecting energy consumption and incorrectly characterizes the existing conditions. Edison asserts that the 3% is not a line loss, but a confirmed operational loss factor from the operation of a lamp in field conditions. CAL-SLA, in Edison's opinion, has also not provided any evidence to support its proposal that Edison's lamp loads should be other than authorized and based on manufacturer specifications which ignore these field conditions.

We are concerned that Edison's reliance on previously authorized lamp loads, as PG&E had, may also not reflect current manufacturers specifications or conditions. We believe that CAL-SLA has presented sufficient justification for our reliance on those specifications even if they do not completely reflect actual field operations. This reliance requires our adoption of the modifications proposed by CAL-SLA for Special Conditions 10 and 12 of the LS-2 schedule.

d. Ownership of Photocells and Related Facilities and Regulated Output Transformers

CAL-SLA recommends that Special Condition 3 of Schedule LS-2 relating to "Switching and Related Facilities" be removed from the tariff schedule. According to CAL-SLA, "switching" refers to an obsolete arrangement under which the streetlight circuit is switched on and off. CAL-SLA states that the current, typical arrangement is to have a photoelectric cell control a streetlight.

CAL-SLA states that, based on its own survey, six of the nine streetlight customers contacted indicated that they owned and maintained the photocells which are part of the otherwise customer-owned pedestal. Under these circumstances, CAL-SLA believes that the retention of Special Condition 3 is unnecessary and its removal would reflect that the customer owns and maintains the photocell. CAL-SLA notes that neither PG&E nor SDG&E have a condition similar to Special Condition 3 nor do these utilities claim they own and maintain the photocells in customer-owned luminaries.

Edison states that CAL-SLA's proposal does not relate to rate design, but rather to customer compliance with existing authorized tariffs. Edison asserts that these tariffs which clearly state Edison's ownership of streetlight switching equipment (i.e., the photocell) are not altered by the customer's belief in his ownership of that equipment. Edison states that the solution to this problem is not to change the tariff to accommodate a minority of customers who are in violation of the terms of the tariff, but to bring those customers into compliance with the tariff. Edison analogizes customers' claims of ownership of the photocell, which is locked and sealed in a separate section of the service pedestal along with any applicable meters, timeblocks or relays, to a residential customer claiming to own the service meter simply because it is attached to its residence.

We similarly find that a review of CAL-SLA's testimony and argument reflects that its study merely revealed what the streetlight customers "believed" and not what was in fact the case. While we certainly agree that the customer could be responsible for maintaining a photocell, the fact that ownership apparently resides in Edison does not guarantee that such maintenance would take place. We therefore find it more prudent for the protection of those streetlight customers who rent streetlights from Edison, for which equipment Edison is ultimately responsible, to maintain the current special condition to ensure continuous streetlighting.

G. Optional Time-Of-Use Meter Charges

Edison has proposed monthly meter charges for its proposed optional TOU schedules in addition to the proposed monthly customer charges. The proposed meter charges are set to cover the differential in metering costs between a conventional meter and a time-of-use meter.

Edison has not included the costs associated with its optional meter plan in its results of operation showing. To ensure the appropriate recovery of revenue, we will therefore reflect the following estimated costs for time-of-use meters in our adopted results of operation: $369,500 in 1988; $1,012,600 in 1989; and $1,559,800 in 1990.

H. Rate Design Between General Rate Case Proceedings

Edison and PSD disagree on how to adjust the various rate components as a result of revenue requirement changes occurring between general rate cases. Edison proposes to hold demand and customer charges constant between general rate cases and make all adjustments in the energy charges. In contrast, PSD proposes to increase demand and customer charges toward their EPMC relationships for revenue requirement increases, but to hold them constant for decreases.

Edison states that its concerns with PSD's approach are not only with the mechanics of calculating the adjustments, but also with the fact that that the attainment of full EPMC rates is not desirable for all rate components. Edison is particularly concerned that total reliance on EPMC will result in creating severe bill impacts and tilting of rates to an extent that would induce uneconomic bypass. Edison believes that its proposal strikes a balance between theoretical and practical considerations in the design of demand rates.

PSD asserts, however, that reliance on Edison's approach may leave demand and customer charges even further from their EPMC relationships than they are today, particularly if Edison's revenue requirement increases. PSD states that its approach ensures that steady progress toward EPMC will be made and makes any back-slide impossible.

With our adoption of rate limiters and other rate design features designed to moderate adverse bill impacts, we do not believe PSD's approach to rate design for intervening rate increases will result in any unwarranted rate impacts which might, independent of all other considerations, further uneconomic bypass. We also believe that PSD's proposal is consistent with our adherence to marginal cost principles for revenue allocation and rate design. The problems encountered in this proceeding which required revenue allocation and rate design caps were created by revenues having been allocated and rates having been designed on concepts other than marginal costs in past years. It is not our intention to retard this process of achieving cost-based rates any further by adopting a means of adjusting rates in the interim which could lead to further separation between rates and marginal costs. We therefore find reasonable and adopt PSD's proposal to increase demand and customer charges toward their EPMC relationships for revenue requirement increases in the intervening ECAC proceedings between general rate cases, but to hold them constant for decreases.

<u>Findings of Fact</u>

1. On December 26, 1986 Edison filed A.86-12-047 requesting: (1) authority to increase base rate revenues by $301.5 million or 5.4% for test year 1988, and (2) attrition increases for 1989 and 1990.

2. I.87-01-017 was issued and consolidated with A.86-12-047 on January 14, 1987 to consider a reduction in Edison's rates.

3. Edison's revised request increases base rate revenues by $79.0 million or 1.5 percent.

4. Six days of public hearings, including a Commission en banc public hearing, were held during April 1986.

5. The Administrative Law Judges' draft decision was issued on November 20, 1987.

6. Edison and PSD have agreed to a labor escalation rate of 3.5% for both 1987 and 1988.

7. Edison and PSD have agreed to the methodology for developing non-labor escalation rates and recommend rates of 2.99% for 1987 and 4.41% for 1988.

8. Edison and PSD are in agreement with respect to the forecast of kilowatt-hour sales as shown in the table Summary of Kilowatt-Hour Sales on page 6 of this decision.

9. With the exception of other operating revenues Edison and PSD have agreed to present rate revenues which include $19.4 million in CLMAC revenues.

10. Present CLMAC rates were established to recover expenses associated with conservation and load management programs incurred prior to test year 1988.

11. Edison estimated certain steam production expenses using a seven-year historical average.

12. Edison proposes to increase accounts 512 and 513 by over 50% due to the development of new criteria for scheduling steam generating unit overhauls.

13. Edison expects the new steam generating unit overhaul criteria to reduce routine activities, but failed to quantify this benefit.

14. Repairs planned for the low pressure turbine rotor at Redondo generating station unit 7 are not performed on a routine annual basis.

15. Edison and PSD recommend that $20.5 million be adopted for test year hydro production expense.

16. Edison and PSD recommend that $17.2 million be adopted for test year other production expense.

17. Edison and PSD are in agreement with respect to the test year level of production expense for SONGS.

18. SDG&E owns a 20% share in SONGS.

19. Edison operates and maintains SONGS.

20. Edison and PSD are in agreement that it is appropriate to consider an increase in NRC fees during the test year through the attrition mechanism.

21. Edison, PSD, and FEA are in agreement with the continuation of the flexible refueling mechanism adopted in Edison's last general rate case for use with SONGS and Palo Verde refuelings.

22. For Palo Verde O&M expense Edison utilized ANPP's zero-based estimate prepared by ANPP managers and supervisors with Edison as a participant.

23. Without changing ANPP's total O&M expense estimate, Edison scaled-up the Palo Verde refueling outage expense to reflect actual experience at SONGS 2 and 3. This resulted in a reduction in ANPP's budgeted O&M expense estimate of $1.2 million.

24. Palo Verde 3 O&M and refueling expenses are addressed in this decision.

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24. Palo Verde 3 O&M and refueling expenses are addressed in this decision.

25. A.87-08-054 will address the implementation of rate changes associated with Palo Verde 3 O&M and refueling expenses.

26. Because of an absence of operating history at Palo Verde, PSD recommends that the O&M expense for these units be determined from the 1985 average O&M expense for 24 large nuclear units.

27. The comparative study used by PSD does not consider differences among nuclear plants, shows O&M expense varied by $20 million above or below the average, reflects an increase in 1986 of 11.8%, and does not exclude refueling expenses.

28. PSD's comparative study is useful for developing a zone of reasonabless for nuclear O&M expenses.

29. The chemical cleaning process that will be performed in conjunction with the replacement of the feedwater heaters is a one-time expense.

30. Edison plans to perform a chemical cleaning process in 1990 on SONGS 2.

31. Edison requests recovery of $2.9 million for expenses previously incurred for the reprocessing of spent nuclear fuel from SONGS 1.

32. Edison did not receive prior approval for the expenses in finding 31 nor did it receive approval of a mechanism for tracking these costs for later recovery.

33. Edison and PSD recommend that $75.3 million be adopted for test year transmission expense.

34: Edison's estimate for account 582, station expense, is based on 1985 recorded without adjustment for growth or productivity.

35. PSD's estimate for account 582 reflects recorded downward trends in labor expense and as a result is $3.5 million lower than Edison's estimate.

36. Edison has replaced a number of its tree trimming crews with contract labor and reflects this in its estimate for account 583, overhead line expense.

37. PSD's estimate for account 583 does not reflect Edison's transition to contract labor.

38. Expenses for account 597, maintenance of meters, were lower for the years 1982-1985 than for the years 1979-1981 because all purchases of mecer locking rings have been assigned to the energy theft program.

39. Unlike PSD, Edison reflected the accounting change for meter locking rings in its estimate for account 597.

40. Edison's underground switch failures have increased from 27.5 per year to 85.8 per year.

41. On April 1, 1987, Edison implemented a new three-year program for the inspection of its underground facilities including a laboratory analysis of the insulating oil in all transformers and switches.

42. The increase in Edison's labor expense for the three-year underground inspection program comes from employees who were involved in new business construction. These employees will be replaced by contract crews.

43. PSD considers the increase in labor for the three-year underground inspection program to be double counting because the labor will be performed by existing employees.

44. PSD does not believe that the increase in underground equipment failures poses an immediate threat to Edison's underground distribution system and recommends against an increase in laboratory analysis.

45. A five-year average of account 598, storm damages, was adopted in Edison's last three general rate cases.

46. PSD recommends an eight-year average of account 598 be adopted to consider more years of a climatic cycle.

47. PSD has not presented evidence that more years of a climatic cycle will result in a more accurate estimate of storm damages.

A.86-12-047, I.87-01-017 ALJ/FSF,SSM/jt

48. Edison requests $4.3 million for posting termination notices on the customer's premises due to PU Section 779.1.

49. Edison has not provided the record with documentation of the study it performed from which it concluded that termination notices by telephone are not less costly than termination notices posted on the customer's premises.

50. PSD's estimated cost of providing termination notices to customers assumes that telephone notices are less costly than posting notices.

51. Edison's participation in Enercom produced savings of $225,000 in 1986 of which 10% was from former customers outside Edison's territory.

52. PSD estimates that Edison's participation in Enercom will yield savings of $775,000 in 1988 based on an increase in the number of participating utilities.

53. PSD did not present evidence that there would be an increase in the number of utilities participating in Enercom in 1988.

54. Edison's benefits from Enercom exceed its costs by six to one.

55. Edison agrees with PSD's use of a three-year average of uncollectibles.

56. Increases during the test year for items minor in nature have not been authorized in the past.

57. A minor increase for postage is likely to occur during the test year.

58. A&G expenses can be separated into two categories: items over which Edison has control and items over which Edison does not have direct control.

59. Customer growth impacts A&G expenses.

60. Customer growth from 1985 to 1988 is expected to be 8 percent.

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58. A&G expenses can be separated into two categories: items over which Edison has control and items over which Edison does not have direct control.

59. Customer growth impacts A&G expenses.

60. Customer growth from 1985 to 1988 is expected to be 8 percent.

61. Pension, medical, dental, and vision plan costs, insurance, franchise taxes, and F/MBE program costs are items over which Edison does not have direct control.

62. Edison's recorded insurance premiums have generally followed market trends.

63. Recently insurance premiums have risen precipitously.

64. Some insurance professionals indicate a decline in insurance premiums.

65. Edison's estimate of insurance premiums does not reflect a softening in the insurance market.

66. Directors and officers insurance protects ratepayers and stockholders.

67. Edison and PSD have agreed to the estimated insurance premiums for crime, nuclear property, nuclear replacement generation, and nuclear liability.

68. PSD reduced Edison's estimate of group life insurance because of insufficient documentation to justify Edison's request.

69. PSD's estimate of outside provider medical costs is based on the latest recorded data and assumes no growth in participants.

70. Edison's annual energy, ECAC, and MAAC rates are calculated using Edison's latest adopted franchise tax and uncollectible rates.

71. The Superfund Tax is a new tax which Edison and experts within the utility industry have interpreted as a deductible tax.

72. Edison and PSD have incorporated the provisions of the Federal Tax Reform Act of 1986 in their tax calculations.

73. Edison estimated 1988 plant-in-service by adding forecasted plant additions from its five-year plant and work element budget to 1985 recorded plant.

74. Edison and PSD have agreed to the depreciation rates to be used in calculating depreciation expense and reserve.

75. Edison and PSD have agreed to guidelines for evaluating PHFU in future proceedings.

76. Edison has agreed to reduce its PHFU estimate by $7.1 million if the PHFU guidelines are applied prospectively.

77. Retroactive application of the PHFU guidelines would result in a $16.2 million decrease in Edison's original PHFU estimate.

78. Without application of the PHFU guidelines 56 parcels of land would remain in PHFU an average of 27 years.

79. A parcel of land valued at $520,000 was double counted in Edison's estimate of PHFU.

80. With the exception of the lag for the State income tax deduction, Edison and PSD are in agreement on the methodology for calculating working cash.

81. The appropriate working cash lag for State income taxes is under consideration generically for energy utilities in A.85-12-050.

82. Edison and PSD are in agreement on the method of calculating attrition and recommend that the 1989 ERAM base level be increased by $9.8 million to reflect a decrease in FERC sales.

83. Edison and PSD have not reflected the impact of Edison's optional TOU meter plan in calculating attrition.

84. Appendix D sets forth a format for developing Edison's attrition filings.

85. PSD has agreed to Edison's capital structure as revised in the September update hearings.

86. Edison's revised capital structure reduced its base rate revenue increase by $18 million and its total revenues including MAAC by approximately $25 million.

87. DRI's November 1987 forecast of 1988 interest rates for AA utility bonds is 9.68%.

88. Edison and PSD do not have the resources to develop and maintain forecasting models for interest rates.

89. DRI is a forecasting service with access to vast amounts of data and an acknowledged expertise it the forecasting of interest rates.

90. PSD's forecast of tax-exempt financing compares favorably with recent recorded data.

91. SDG&E was authorized to recover the unamortized issuance costs associated with perpetual securities in D.87-07-079.

92. The financial models of the parties provide a range for ROE of 11.5%-18.4%.

93. Interest and inflation rates have been low and relatively stable and show a considerable improvement over test year 1985.

94. Edison's recent financial performance indicates it is a strong company.

95. Edison does not face a major reasonableness review of SONGS 2 and 3.

96. Edison's MAAC rates are calculated using Edison's latest adopted ROE.

97. In 1974 Edison entered into a lease arrangement to procure its nuclear fuel requirements for SONGS. The lease permitted Edison to finance its nuclear fuel at short-term rates and was not reflected on its balance sheet.

98. An accounting change by the Financial Accounting Standards Board requires Edison, beginning in 1987, to reflect capital leases on its balance sheet.

99. Commission policy in recent years has resulted in fuel inventory assets being removed from rate base and allowed carrying costs at short-term interest rates through ECAC.

100. D.87-05-059 authorizes Edison to guarantee short- and intermediate-term debt instruments for the express purpose of financing nuclear fuel.

101. Edison is not required to terminate its lease arrangement for nuclear fuel.

102. Full recognition of SONGS and Palo Verde nuclear fuel in rate base would increase Edison's rates by $48 million.

103. Fuel is a commodity that can be used as collateral for financing and is distinguishable from fixed plant and land.

104. Carrying costs for Palo Verde nuclear fuel inventory are currently included in Edison's IMAAC.

105. Coal inventory currently receives rate base treatment.

106. Edison spent $2.4 million in affirmative case costs in anticipation of demonstrating the reasonableness of Edison's investment in Palo Verde.

107. Edison did not seek or receive approval for Palo Verde affirmative case costs or a mechanism for tracking these costs prior to their incurrence.

108. Edison has not provided value-based reliability criteria or a comprehensive study evaluating the range of alternative uses for its aging oil and gas generating units.

109. Edison agreed to provide, coincident with its fall 1988 resource plan, value-based reliability criteria which address PSD's concerns as stated in Exhibit 53.

110. With the exception of Ormand Beach unit 2 and Huntington Beach unit 2 Edison has not provided PSD with adequate justification for plant modifications or two-shifting to reduce the minimum generation capability at certain oil and gas generating units.

111. Edison requests rate base treatment for $104.6 million for the DC Expansion.

112. PSD recommends, based on its cost-effective analysis that Edison be limited to recognition of an investment much less than $47.8 million.

113. Time differentiating the value of energy purchased and capacity received over the DC intertie increases PSD's cost-effectiveness analysis by $19 million.

114. Excluding 1400 MW of peaking resource additions which are are not funded or not under construction from PSD's analysis may increase its recommendation by $5 million.

115. PSD's analysis of the DC Expansion was developed using forecasted gas prices based on the 1986 price of LSWR.

116. LSWR prices are subject to fluctuations and have increased sharply in 1987.

117. Edison's DC Expansion analysis does not reflect lower gas prices in 1986.

118. On November 23, 1987 PSD filed a motion to set aside submission with respect to the DC Expansion project and to compel production of documents, attachment 6 to the motion.

119. Edison and LADWP signed a letter agreement dated December 2, 1985 which could impact the cost-effectiveness of the DC Expansion project by linking it with other transmission projects.

120. Edison has accepted the responsibility and attendant risk, of demonstrating the reasonableness of its investment in the DC Expansion project at the time it becomes operational.

121. The cost-effective amount of investment in the DC Upgrade should be litigated in Edison's application for a CPCN to construct the Devers-Palo Verde line. The amount of investment ultimately found to be reasonable may not exceed the amount of investment determined to be cost-effective in the context of the Devers-Palo Verde proceeding. Should our subsequent cost-effectiveness review yield different results, the DC Expansion cap adopted in this decision should be adjusted.

122. Edison and PSD have jointly submitted a proposed procedure (Appendix A) which provides for modification of the existing MAAC to include recorded investment-related revenue requirement and the recorded revenues related to specific plant additions estimated to cost more than $50 million.

123. For this rate case Edison and PSD propose that MAAC rate level increases, equal to 75% of the annualized revenue requirement, be authorized for each of four projects once they are commercially operational: Balsam Meadow, Devers-Valley-Serrano, DC Expansion, and Devers-Palo Verde.

124. The annualized CPUC jurisdictional revenue requirement for the projects to be included in MAAC is $47.6 million for Balsam Meadow, $25.9 million for Devers-Valley-Serrano, $15.9 million for DC Expansion, and $39.1 million for Devers-Palo Verde.

125. The Devers-Valley-Serrano project became commercially operational on July 22, 1987.

126. The Balsam Meadow project became commercially operational on December 1, 1987.

127. Edison's competing for the customer program will provide customers with the opportunity to shift loads and reduce their overall energy bills and allow Edison to operate its generating stations at higher loads and efficiencies.

128. EPRI is conducting electric transportation research.

129. Edison has not demonstrated that its electric transportation RD&D project is unique to Edison or that similar benefits cannon be obtained from EPRI.

130. Edison's alternate fuels, occupational and community safety, and advanced energy conversion RD&D programs are generally beneficial to the ratepayers, but are low priority.

131. The natural resources management program is Edison's lowest priority RD&D program.

132. Edison's actual 1988 EPRI dues are $14.7 million.

133. There is a need for increased utility emphasis on long-term, end-use RD&D that is consistent with the utility's resource plan and coordinated with other California utilities and experienced research organizations.

134. The Institute's recommendations do not conflict with Edison's bidding procedures.

135. Edison has participated with the Council in a review of Institute proposals, and indicated that some of these projects will be funded.

136. R.87-10-013 was issued to consider a generic proceeding for coordination and approval of all RD&D budgets.

137. Account 930.2 is a miscellaneous A&G account in which RD&D program expenditures are recorded.

138. A one-way balancing account for RD&D expenditures will insure that RD&D funds are spent on RD&D programs.

139. Edison can change RD&D programs without prior Commission approval.

140. Edison's analysis indicates that from 1976-1985 it experienced average annual productivity gains of 1.6 percent.

141. PSD based on its econometric model forecasts a productivity gain of 3.4% for test year 1988.

142. The adopted operating expense as shown in Appendix C, without a productivity adjustment, yields a 2.4% productivity gain.

143. Edison and PSD were not in agreement on the data base to be used in evaluating employee compensation.

144. PSD's analysis of employee compensation did not consider total employee compensation, provide a range of data used for comparison, and adequately adjust the survey data for duplication of jobs and companies.

145. Edison and PSD are in agreement on the ratemaking treatment for gains on sales of utility assets to affiliates and net income of utility-related subsidiaries.

146. In A.87-05-007 Edison and PSD have submitted a joint exhibit agreeing to the markup royalty for services provided by the utility and the guidelines for utility employee transfers to affiliates.

147. PSD's recommended royalty to be paid by affiliates on gross revenues is addressed in A.87-05-007.

148. Edison has stipulated to PSD's recommendations for hazardous waste management.

149. PSD's hazardous waste recommendations only identify manufactured gas hazardous waste sites.

150. PSD's hazardous waste recommendations require Edison to file two different hazardous waste reports each year.

151. R.87-02-026 was initiated to address long-term goal setting, verification procedures, and annual reporting for utility F/MBE programs.

152. Edison increased its dollar awards to F/MBEs from $38.3 million in 1984 to $74.8 million in 1986 and increased the number of awards from 3,805 to 5,025 for the same period.

153. Over the last three years less than 4.5% of all contract amounts have gone to F/MBEs.

154. Demand side management refers to ratepayer funded programs undertaken by the utility to affect customer energy consumption patterns.

155. A determination of the appropriate funding levels for demand side management requires consideration of the current economic and resource conditions impacting the utilities regulated by this Commission.

156. The funding of demand side management programs is impacted by the Commission's elimination of the Electric Revenue Adjustment Mechanism (ERAM) for large power customers in D.87-05-071, one of the policies adopted in the 3-Rs Rulemaking to address the problems created by customer bypass of the utility system.

157. Despite the elimination of ERAM for large power customers, the Commission has determined that the most cost-effective conservation programs should still be retained for this customer group and that the utilities' incentives to pursue effective conservation remains unchanged for the commercial and

residential classes who are not impacted by the elimination of ERAM.

158. The Commission continues to believe that long-range conservation remains an important goal and that utilities should continue to promote reasonable conservation and efficiency options to customers.

159. The Commission has directed utilities to refrain from using ratepayer funds for utility marketing programs aimed at increasing utility profits when ERAM is eliminated.

160. As in the case of the development of marginal costs, parties relying on computer models and related data to develop demand side management recommendations must provide this information for purposes of cross-examination and rebuttal.

161. Because the results of CEC's cost-effectiveness study were provided following the close of hearings and submission dates for opening and reply briefs on demand side management, this information cannot be considered part of the record in this proceeding.

162. Ethics and fairness dictate that an extension to file a brief granted to one, but not all, parties to a proceeding may not be used as an opportunity to respond to briefs which were timely filed.

163. Because the CEC inappropriately responded in its reply brief to the previously filed reply brief of PSD, that portion of CEC's reply brief cannot be considered in this proceeding.

164. PSD's proposed funding level of $1.9 million for the Residential Information program provides sufficient funds, based on an analysis of historic and current data, to provide the information necessary to communicate the need and the manner in which residential customers can conserve energy and is therefore reasonable.

165. Edison's proposed funding level of $4,149,000 for residential Energy Management Services would maintain the current

audit mix and include a reasonable increase in audits under the Residential Survey Program and is therefore reasonable.

166. PSD's proposed funding level of $768,000 for residential Weatherization and Retrofit Incentives includes appropriate limitations on those incentives and designations of the areas to be targeted and is therefore reasonable.

167. The funding level of $1.4 million for Residential New Construction to which PSD and Edison have agreed provides for sufficient incentives under these programs and is therefore reasonable.

168. To ensure the proper allocation of funds for Residential New Construction, it is not necessary to adopt PSD's proposed restriction on funding for central electric heat pumps, but it is necessary to adopt PSD's recommendation regarding the elimination of funding for the heat pump water heater found to be non cost-effective.

169. To ensure that ratepayer funds are applied to only efficient and cost-effective conservation programs, it is reasonable to direct Edison to investigate lower incentives for all such programs.

170. The funding level for Edison's Residential Conservation Direct Assistance program of $5.4 million, adopted in Edison's 1987 CLMAC and proposed by Cal-Neva in this proceeding, is based on the program's cost-effectiveness, the lack of market saturation by the program, the need for continued conservation by low income groups, the uncertainty of previously applied federal grants, and the questionable applicability of the 1986 cost per measure recommended by PSD in the absence of those grants and is therefore reasonable.

171. PSD's funding recommendation of $767,000 for Non-Residential Information reflects a substantial increase over the previously authorized level, takes into account a full year of activity under the Major Accounts Representative Program, and

provides adequate funding for "outreach" and is therefore reasonable.

172. PSD's recommended funding level of $8,028,358 for Non-Residential Energy Management Services is based on recent recorded costs and is therefore reasonable.

173. PSD's original funding recommendation of $1,227,000 for Non-Residential Energy Management Incentives and its originally proposed allocation of funds between small, medium, and large power customers ensures continuation of this program at a reasonable level to these customers, maintains cost-effective conservation programs for each of these customer groups consistent with D.87-05-071, and is therefore reasonable.

174. PSD's funding level of $0.34 million for Non-Residential Energy Management Incentives-Administration properly reflects the correlation between incentive levels and administrative costs and is therefore reasonable.

175. A funding level of $2.5 million for Non-Residential New Construction ensures that Edison can achieve the legitimate and cost-effective goals of this program even with the inclusion of large power customers and is therefore reasonable.

176. In numerous recent decisions, the Commission has considered funding for Thermal Energy Storage programs; in none of these orders or D.87-05-071, however, has the Commission determined that any load retention resulting from TES installations is the equivalent of a utility marketing function.

177. Edison's Thermal Energy Storage program is a demand side management program clearly directed to the goal of improving load management for customers installing TES equipment, is potentially able to retain customers who might otherwise have chosen self-generation, and is not specifically aimed at increasing Edison's sales and revenues.

178. The load shifting and load retention aspects of Edison's Thermal Energy Storage program, based on the previous findings, can

be considered in determining the program's cost-effectiveness and funding.

179. It is reasonable to direct Edison to continue its efforts to quantify the gas-side impact of its Thermal Energy Storage program consistent with the recently revised Standard Practice Manual for Economic Evaluation of DSM Programs to ensure the most accurate assessment of its cost-effectiveness.

180. Edison's TES program is a cost-effective load management program which can be extended to small, medium, and large power customers.

181. To ensure its continued cost-effectiveness, Edison's TES program should be closely monitored in the coming years through the reporting requirements established by Resolution E-3053 and the establishment, for accounting and reporting purposes, of the categories of Load Shifting (Medium/Small and Large Customer) and Load Retention (Medium/Small and Large Customer) suggested by PSD.

182. To ensure the continuation of Edison's TES program at a cost-effective level, it is reasonable to adopt a funding level of $4 million, an amount which is based on recorded 1986 expenditures with allowances for a reasonable increase in program activity and an incentive level of $200/kW.

183. Edison's proposed funding level of $1,641,000 for its Water Storage Program ensures that the program can achieve its legitimate program goals directed at the needs of Edison's agricultural customers and is therefore reasonable.

184. To ensure the cost-effectiveness of its Water Storage Program, it is reasonable for Edison to undertake whatever reasonable cost-cutting measures are possible to limit any unnecessary and non-cost-effective spending.

185. It is appropriate to defer funding for Edison's Residential and Non-Residential Marketing programs until further analysis of the marketing issue is undertaken in the 3-Rs

Rulemaking in which marketing issues for both ERAM and non-ERAM customers should be reviewed.

186. A funding level of $7,325,000 for the Measurement and Evaluation Program covers the costs associated with the technical assessments, data collection, and analysis which are required to be undertaken in this program and is therefore reasonable.

187. To ensure the proper designation of ratepayer funds, it is reasonable to include the funding for Edison's load research activities as a demand side management expense.

188. To provide consistency in the review of every utility's demand side management programs, it is reasonable for the reports required for Edison's demand side management programs to be developed using the same guidelines adopted for PG&E in D.86-12-095 at pages 111 through 118.

189. PSD's proposed funding level of $3.5 million for Edison's Support Programs take into account the needed levels of activity, promotion, management, and administration to support Edison's conservation programs and is therefore reasonable.

190. It is reasonable to consolidate all demand side management program funding in base rates starting with Test Year 1988 with the exception of TES incentive payments related to contracts executed prior to January 1, 1988, which should continue to be reflected in the ERAM balancing account consistent with D.82-12-055.

191. To enhance Edison's flexibility in managing its demand side management program funding, the current $2.5 million allowance for Edison to make funding shifts within the three existing major program categories (Residential Conservation, Commercial/ Industrial/Agricultural Conservation, and Load Management) without a formal advice letter filing, but with notice to our Commission Advisory and Compliance Division and the Division of Ratepayer Advocates.

192. For funding shifts between the three major conservation program categories or for shifts of greater than $2.5 million within those categories, Edison is required to make an advice letter filing.

193. Edison's management flexibility would not be improved by increasing the major conservation program categories as recommended by PSD, and the existing categories, named above, should be continued.

194. Edison has complied with Ordering Paragraph 12 of D.84-12-068 by reducing its Corporate Energy Management labor budget by over 20% and providing a numerical count by job category and salary range and a description of each job category.

195. The Commission's need to track conservation program spending has increased proportionately with our need to ensure the cost-effectiveness of those programs.

196. The generic demand side management definitions being established in the Reporting Requirements Manual should be used by Edison in future rate case, offset, and advice letter filings to assist the Commission's tracking of program expenses.

197. The continued effective development of QF resources is an important goal which will permit Edison to meet its resource needs.

198. Overall program funding for Edison's Cogeneration/Small Power Production Program of $1,765,000, with reductions of $200,000 in 1989 and $550,000 in 1990 if warranted on the basis of a periodic analysis to be undertaken by PSD and Edison, will ensure that the legitimate goal of this program is met and its continued cost-effectiveness is monitored and is therefore reasonable.

199. Bypass is a condition which occurs when a utility customer chooses to generate its own energy rather than accept the service available from the local public utility.

200. Of particular concern is "uneconomic" bypass.

201. The Commission has found that "uneconomic" bypass results in "an inefficient allocation of society's resources."

202. To address the problems created by bypass for the utility and its customers, the Commission has adopted several policies in R.86-10-001, the 3-Rs (risk, return and ratemaking) rulemaking, including a commitment to revenue allocation based on Equal Percent of Marginal Cost (EPMC), the elimination of the Attrition Rate Adjustment and the Electric Revenue Adjustment Mechanism for the large light and power class, and the use of special contracts between the utilities and customers in the large light and power class.

203. While the appropriate forum for developing policies governing our response to bypass is clearly R.86-10-001, these policies play an important and integral role in our findings in this general rate case on issues related to marginal cost, revenue allocation, rate design, and demand side management programs.

204. Bypass has also been made a separate issue in this proceeding by Edison's inclusion in its prepared testimony of an exhibit intended to quantify the extent of bypass expected in the future.

205. Edison is to be commended for its attempt to quantify the effects of bypass; however, serious questions have been raised regarding the assumptions and approach used by Edison and the accessibility of Edison's models and data base.

206. Our findings in this decision regarding the use of and access to computer models in developing marginal cost estimates are equally applicable to the parties' review of Edison's model and data base used in developing its estimate of the bypass impact.

207. While forecasts of bypass may be helpful in the future to determine the impact of our remedial actions, adoption of a particular estimate of bypass is not necessary in this proceeding.

208. Because the Commission's goal is to stem the tide of uneconomic bypass, it is reasonable to continue to encourage self-generation, based on the use of renewable resources, to the extent that it is required and economically efficient.

209. With this decision, the Commission continues its commitment to marginal cost ratemaking.

210. Marginal costs provide cost-based rates and accurate price signals regarding a customer's energy consumption.

211. Uniformity between marginal costs and the related concept of avoided cost which is used as the basis for payments to qualifying facilities is appropriate to the extent possible and practicable.

212. Current methodologies for developing avoided costs must be taken into consideration in calculating QF payments.

213. In Edison's last general rate case, the Commission concluded that use of a uniform computer model in developing marginal costs would end suspicion and enhance understanding of computer models.

214. The Commission also directed Edison in its last general rate case to provide computer data upon the filing of its application to avoid the data gathering problems which PSD had experienced in that proceeding.

215. Since the issuance of the Commission's decision in Edison's last general rate case, AB 475 has been enacted adding statutory provisions requiring, among other things, that any computer model and related data base that is the basis for any testimony or exhibit in a Commission proceeding shall be made available to the Commission and parties to hearings to the extent necessary for cross-examination and rebuttal.

216. Despite the efforts of the Commission and the Legislature, little progress toward uniformity in production cost models or availability of related data has been made within the context of the general rate case.

217. In this proceeding, instead of a uniform model being used by all parties, the Commission was presented with a total of three models, the efficacy of each of which was the subject of debate.

218. The timely provision of computer data remained a problem in this proceeding as interested parties were still without such data as hearings on the issue of marginal cost commenced.

219. The difficulty of assessing the validity of various computer models is made more acute in the setting of a general rate case in which the Commission is required to hear and decide a myriad of issues within a strict timetable.

220. The problems associated with the Commission deciding issues related to the verification of complex computer models, a significant problem in the general rate case, will worsen if IERs (incremental energy rate) are to be updated annually in ECAC proceedings which are already burdened by substantial time and staffing limitations.

221. In adopting forecasted results, the Commission must not leave to chance its understanding of the tools used to achieve those forecasts.

222. Based on the preceding findings, in the next general rate cases, ECAC proceedings, or other related proceeding identified in A.82-04-44, et al., of Edison, PG&E, and SDG&E, it is reasonable to require all parties presenting testimony requiring the use of a production simulation model to develop marginal or avoided costs to provide a "base case" run using the same computer model.

223. Each party will also have the opportunity to present testimony using its model of choice and explain its preference for that model.

224. Uniformity in computer modeling, as a starting point, will aid the Commission in determining whether model, assumption, or methodological differences are causing different results.

225. It is reasonable for all parties to use the ELFIN computer model to perform the "base case" run in future rate proceedings due to its accessibility and its current application to multiple uses.

226. Any shortcomings in the ELFIN model can be addressed by each party either suggesting a means of adjusting the model to overcome any problem or citing the deficiency as a basis for reliance on an alternate model or approach.

227. To ensure access by all parties to input assumptions and data related to computer models used to calculate a utility's IERs and marginal or avoided energy costs, a uniform procedure for exchanging this information prior to hearings in all utilities' ECACs, general rate cases, or any other proceeding adopted in A.82-04-44, et al. for updating IERs, is appropriate.

228. It is reasonable for the procedure envisioned in the above finding to include a workshop to be held no later than one week following the filing of the utility's testimony for the purposes and in the manner described in our discussion of marginal energy costs.

229. Work related to the implementation of AB 475 will ultimately determine the manner in which models are to be used and accessed.

230. Due to greater certainty regarding the methodologies to be used for calculating marginal and avoided energy costs, it is not appropriate in this proceeding for the adopted IER to result from the averaging of the parties' proposed IERs.

231. The Commission has endorsed the calculation of two IERs -- one for marginal energy cost determinations and one for avoided energy cost determinations -- in order to properly reflect the contribution made by qualifying facilities in avoiding utility energy costs.

232. While the method for calculating avoided energy costs will ultimately be developed in A.82-04-044, et al., the Commission has continued to move in the direction of applying the "QF In/QF Out" methodology for short-run, as well as for long-run, avoided energy cost calculations.

233. Although uniformity in the calculation of marginal and avoided costs greatly simplifies the task of determining those costs, such an approach does not allow the Commission to meet its obligation of providing the most accurate prices to QFs based on avoided costs and, at the same time, to provide the most accurate price signals to consumers regarding their electric consumption.

234. PSD was the only party to this proceeding presenting IER results based on a "QF In" (marginal cost) approach and a "QF In/QF Out" approach.

235. Because PSD's IER results were the least controverted in this proceeding, reflected the proper correlation between the two resulting IER estimates, were within the range of IERs proposed by the other parties, and were derived from the same model, it is reasonable to adopt PSD's estimate of 9,626 Btu/kWh to be used for the marginal energy cost calculation and 9,775 Btu/kWh to be used for the avoided energy cost calculation.

236. It is appropriate to adopt an annual IER in this proceeding due to the likelihood of the IER being the subject of an annual update; however, this value should remain in effect until updated as prescribed in A.82-04-44, et al.

237. Adoption of PSD's IER estimates is not an approval of PSD's "QF In/QF Out" methodology, an issue properly reserved for A.82-04-044, et al., is not an endorsement of all of PSD's assumptions, and is not an acceptance of Edison's position that changes in such input assumptions have little impact on the calculation of the IER.

238. The sensitivity runs necessary to decide the issue of the impact of input assumptions on the IER calculation are not a part of the record in this proceeding.

239. Because the external adjustment of ELFIN model results to reflect start-up and no-load costs may result in "double-counting" of those costs, it is reasonable that the adjustment be reduced in the amount of the double-counting.

240. Due to the likelihood of the IER being updated on an annual basis, the resolution of the assumptions at issue in this proceeding provides useful insight into the proper determination of similar assumptions in the future.

241. The guiding principle in evaluating input assumptions is that the best assumptions embody the most up-to-date, verifiable information.

242. Based on more recent information and the correct standard of evaluation, the CCC has provided the Commission with the most reasonable assumptions regarding Edison's base load unit (coal and nuclear) production.

243. Based on the most recently available data, Edison's estimate of PNW economy energy and the CCC's estimate of PSW economy energy are reasonable.

244. The basis for determining what is a "firm" power purchase is the same in calculating an IER as it is in developing the utility's ERI (Energy Reliability Index).

245. In evaluating an agreement in terms of its inclusion as a firm resource assumption used in calculating an IER, the focus is properly on the utility's commitment to purchase the power, rather than the economic benefits of the agreement.

246. In assessing whether a utility is truly obligated in a power purchase, the totality of circumstances surrounding the contract (i.e., its status as to the two parties, its status as to the necessary governmental approval, and, least important, its acceptability as to price) must be examined.

247. Based on the criteria outlined in the preceding finding, the BPA MOU cannot be considered a firm power contract under any circumstances while the PP&L and PGE contracts, having a history of a greater level of commitment by the parties, can be considered firm purchases.

248. Based on the most recent data, the CCC's estimate of 12,694 gWh of QF generation is reasonable.

249. It is reasonable to assume that future forecasts should provide more specific and verifiable results regarding the causes and effects of minimum load conditions.

250. PSD's forecasted average price of gas of $2.52/MMBtu is accurate and therefore reasonable.

251. It is reasonable to adopt the undisputed portions of PSD's and Edison's joint exhibit on marginal energy costs and Edison's undisputed changes to factors used in the calculation of avoided energy costs to the extent that these agreements and calculations are not altered by our preceding findings.

252. In past general rate case decisions, the Commission has concluded that a suitable proxy for the marginal demand costs of generation is the annualized value of a combustion turbine.

253. The generation ($69.48,kW) and transmission ($33.10/kW) marginal demand costs jointly proposed by Edison and PSD, modified to reflect an updated O&M loading factor and the franchise fees adopted in this proceeding, are derived from the appropriate methodologies and are therefore reasonable.

254. The record in this proceeding does not include evidence to demonstrating that the basis for applying the ERI to adjust avoided capacity prices for QFs is equally applicable to an adjustment of generation marginal demand costs used for revenue allocation and rate design purposes and therefore is insufficient to justify the application of the ERI to such demand costs at this time.

255. To determine the applicability of the ERI to generation marginal demand costs, it is reasonable to direct PSD and Edison to examine this issue in Edison's next general rate case.

256. The Commission has made clear that the proper calculation of avoided capacity costs requires an adjustment of the annualized value of a combustion turbine in order to reflect system reliability.

257. The Commission has indicated its preference for using an Energy Reliability Index (ERI) based on an Expected Unserved Energy (EUE) target as the basis for adjusting the value of the combustion turbine used as a proxy for avoided capacity costs.

258. The ERI proposed by Edison in this proceeding relies on a consistent and integrated set of data, employs an analytically supportable derivation of the expected unserved energy level, and is consistent with our findings in D.86-07-004 and D.86-11-071.

259. The ERI proposed by Edision is appropriate to use as the basis for calculating Edison's ERI in this proceeding as modified to correct certain flawed input assumptions related to Edison's firm resources.

260. Based on our finding that the status of a firm power purchase agreement depends on its status as to the two parties involved, the acquisition of necessary government approval, and the negotiated price, the BPA MOU cannot be included as an input assumption in calculating Edison's ERI, while the PP&L and PGE contract, which have attained greater certainty, can and were properly included as firm resource assumptions.

261. Because the ERI should equal the average EUE calculated with and without the block of additional capacity being valued, divided by the EUE target, Edison erred by failing to remove any as-available QF resources from its ERI calculation.

262. The CSC has provided a reasonable estimate of as-available QF capacity (45 MW) to be excluded from the calculation of Edison's ERI calculation.

263. Based on the previous findings, an ERI adjustment factor of 0.43 for 1988 is reasonable and should remain in effect until updated or revised as prescribed in A.82-04-44, et al.

264. The reinstatement of Standard Offer 2 is an action specifically reserved to A.82-04-44, et al., and will not be decided in this proceeding.

265. Although marginal distribution and marginal customer costs are distinct concepts both in terms of definition and calculation, these two costs must be examined together for the purposes of determining which of the costs of customer access to the system are attributable to marginal customer costs and which are attributable to marginal distribution costs.

266. D.86-08-083 involving PG&E's adopted marginal costs was to have served as the basis for establishing certain principles to be used in the calculation of marginal customer costs for all utilities.

267. The principles adopted in D.86-08-083 and intended to be applied to all utilities included the inclusion of marginal customers costs in the revenue allocation process; the use of the weighted average of incremental and decremental costs to calculate marginal customer costs; and the inclusion in marginal customer costs of the customer-related costs associated with meters, service drops, final line transformers, access equipment replacement and improvement, and distribution equipment directly assignable to a customer class.

268. The goal of marginal cost ratemaking is to provide accurate price signals regarding a customer's consumption and is achieved by relying on a methodology which most precisely determines the marginal cost related to customer access and maintenance on the utility system.

269. The weighted average incremental/decremental cost approach is a methodology which achieves the goal stated in the previous finding.

270. The question of revenue shortfalls is not necessarily relevant in determining the appropriate methodology for calculating marginal costs.

271. The most equitable way in which to determine class revenue responsibility is by viewing the impact of such changes not in isolation, but in terms of their effect on a utility's total

costs, a goal achieved through the Commission's adopted approach to calculating marginal costs.

272. While the parties to this proceeding generally followed the principles adopted in D.86-08-083 in making their marginal customer cost recommendations, all, except for TURN, ignored the Commission's directive to use the weighted average of incremental and decremental costs in calculating marginal customer costs.

273. In this proceeding, no "fully developed estimate" of both incremental and decremental costs has been provided.

274. Given the methodologies proposed in this proceeding, only PSD's TSM (transformer, service drop, and meter) approach is a "usable" proxy for the weighted average of incremental and decremental costs.

275. PSD's determination of incremental costs based on the TSM approach is closest to the intent of D.86-08-083 to the extent that it is a conservative estimate of those costs, a result achieved by treating final line transformers for residential and small light and power customers as demand-related costs.

276. To bring Edison's marginal customer costs closer to those intended to be implemented following D.86-08-083, it is reasonable to adopt PSD's incremental customer cost estimate exclusive of final line transformers as the proxy for the weighted average of Edison's incremental and decremental customer costs.

277. It is reasonable for the incremental cost estimate adopted in this proceeding to reflect the exclusion of line transformers for all customer classes to ensure equal treatment of these classes in the revenue allocation process.

278. It is reasonable to direct all electric utilities and PSD in forthcoming general rate cases to base their recommended marginal customer costs and numerical estimates of those costs on the weighted average of the utility's incremental/decremental costs.

279. Once Edison's incremental and decremental costs are properly presented, it will no longer be necessary to rely on a proxy which excludes an otherwise properly recognized customer access cost (i.e., final line transformers) from the calculation of marginal customer costs.

280. PSD's approach to calculating marginal customer costs for streetlight customers and the inclusion of those costs in the revenue allocation process is reasonable based on the Commission's approach to calculating marginal customer costs and to including streetlighting in the revenue allocation process except for the end-use costs reflected in streetlight facilities charges.

281. To ensure that all costs, including those related to distribution, are properly included in marginal customer costs, it is reasonable to direct Edison and PSD to undertake analyses and record-keeping to achieve this result.

282. Edison's and PSD's proposed marginal distribution cost, as modified to reflect our findings on marginal customer costs, is based on the appropriate methodology and should be adopted.

283. It is reasonable to direct Edison and PSD to examine the effects of basing their regression analysis used to calculate marginal distribution costs on the load measured by the sum of the maximum demands on distribution substations to ensure the most precise estimate of these costs.

284. Time-differentiated marginal costs are an important factor in developing rate design, evaluating conservation and load management programs, and making other resource decisions.

285. In adopting marginal cost time-of-use or costing periods, consideration must be given to establishing periods which maximize differences between periods and minimize differences between hours within those periods, to enhancing customer understanding of the periods, to ensuring continuity over time, to avoiding rate shock from changes in time periods, and to minimizing any resulting administrative burden.

286. Based on the record in this proceeding, the costing periods to which Edison and PSD have agreed are supportable and should be adopted.

287. In future rate cases, parties are encouraged to provide information aimed at improving the largely judgmental science of developing costing periods.

288. The Commission's reliance on marginal cost principles achieves equity in rates by relating the costs imposed on the utility system to the customer responsible for those costs.

289. In recent years, the Commission has adhered to a policy that, to the extent practical, total revenue should be allocated to ratepayers on the basis of their share of the utility's marginal costs.

290. In determining the appropriate methodology to use in allocating revenues, the goal of achieving marginal cost-based rates must be balanced against the potentially negative impact on certain customer groups resulting from the restructuring of revenue responsibilities.

291. The Equal Percent of Marginal Cost (EPMC) approach to revenue allocation allocates the revenue requirement on an equal basis relative to the marginal cost-based burden each customer class imposes on the system.

292. The Commission has made clear its commitment to the EPMC approach for revenue allocation as the most accurate way to reflect costs which customers impose on the system and as an effective response to the threat of bypass.

293. Based on the preceding findings, it is reasonable to adopt an EPMC revenue allocation for Edison.

294. With the adoption of an EPMC methodology, the Commission must also consider the manner in which it will be implemented and the extent to which it will be applied to all customer classes and to all rate schedules within those classes.

295. Because Edison's present rates are currently quite far from EPMC, it is reasonable for the Commission to adopt a phase-in of the full EPMC revenue allocation adopted for Edison to mitigate the adverse impact on certain customer groups caused by the shift in revenue responsibility.

296. A modification of Edison's phase-in revenue allocation approach is best suited to the Commission's goals of achieving a full EPMC revenue allocation while mitigating any adverse impacts.

297. It is reasonable for the adopted phase-in approach to move each class 1/3 of the way to full EPMC, with a cap of 5% on increases to any class in the first year with any remaining revenue decreases to be spread to the large power classes in proportion to the deviation of each class from full EPMC.

298. The adoption of a 5% cap for residential provides adequate relief from a rate shock while still providing significant rate reductions for large power customers.

299. Because the intent of this decision is to achieve a full EPMC revenue allocation for Edison by 1990, it is reasonable to reflect this intent in any revenue allocation proposed for Edison in 1989 and 1990.

300. Due to our partial elimination of the Attrition Rate Adjustment (ARA) proceeding and our reliance on ECAC for PG&E revenue allocation and rate design between general rate cases, Edison's ECAC proceeding is the appropriate forum for considering any adjustments of Edison's inter-class revenue allocation in 1989 and 1990.

301. It is not reasonable for the consideration of revenue allocation issues in ECAC to include relitigation of the marginal cost structure and levels adopted in this proceeding.

302. To ensure the continued move toward an EPMC revenue allocation for Edison, it is reasonable to allocate revenue changes to rate schedules occurring between this rate case and Edison's 1989 ECAC on the basis of the system average percentage change in

order to maintain the relationships adopted in this proceeding and to identify in Edison's 1989 and 1990 ECAC proceedings the revenue allocation to be applied to intervening offset filings made after each of these proceedings.

303. Because of the minor nature of the adjustment involved, it is reasonable to except from the approach identified above any rate adjustments of less than 1% and allocate these increases on an equal cents per kWh basis.

304. In the absence of marginal costs calculated for the small light and power class, it is reasonable to base the intra-class revenue allocation for that class on an equal percent of present rate revenues, except for Schedules TOU-GS and GS-2 for which the revenue allocation will be determined by applying to the adopted rates the billing determinants to which Edison and PSD have agreed.

305. The record is insufficient in this proceeding to order a cost-based intra-class revenue allocation for the agricultural rate schedules.

306. In the absence of a cost-based intra-class revenue allocation for the agricultural rate schedules, it is reasonable to allocate any revenue shortfall resulting from the implementation of new agricultural rate options equally among all agricultural rate schedules.

307. Because it is our goal to achieve intra-class, as well as inter-class, revenue allocations based on EPMC, it is reasonable to adopt the EPMC revenue allocation to rate schedule in this proceeding for the large power customer group and to direct Edison to collect the data necessary to achieve such an intra-class revenue allocation for the small light and power and agricultural rate schedules in Edison's next general rate case.

308. Despite the low, off-peak energy usage by streetlight customers, it is energy consumption nonetheless and as such the energy, demand, and customer costs related to streetlighting are properly included in determining class revenue allocation.

309. Because the streetlight facilities charge is related to an end-use and not to the components which are included in a marginal cost revenue allocation, it is reasonable to continue to exclude that charge from the revenue allocation process.

310. It is unnecessary to include any forecasted contract rate revenue deficiency in the revenue allocation process at this time.

311. Issues related to the manner in which the revenue deficiency resulting from contract rates is to be determined and allocated are appropriately considered in the 3-Rs Rulemaking in which the guidelines for special contracts and contract rates are being developed.

312. It is reasonable to include in the revenue allocation adopted in this proceeding the total revenue requirement adopted for Edison as of January 1, 1988.

313. The Commission's current rate design philosophy is to achieve easily understood, cost-based rates which are designed to provide accurate and understandable price signals to which the customer can respond, to reflect a customer's usage patterns and characteristics, to recover the customer group's revenue requirement, and to mitigate any negative bill impacts.

314. Our reliance on previous decisions relating to PG&E's adopted rate design is appropriate as a means of identifying current Commission rate design policy; determining whether that policy is to be continued, modified, or abandoned; and ensuring, to the extent possible, consistent treatment of all ratepayers.

315. The baseline quantities proposed by Edison and PSD, including modifications required in the seasons and allocations for Zone 15 customers, are based on the appropriate methodologies, considerations, and statutory requirements applicable to the determination of baseline allowances and are therefore reasonable.

316. It is appropriate to implement the baseline quantities adopted in this proceeding effective with the next seasonal change.

317. The goal of achieving cost based rates is not outweighed by the need for simplicity in rate design in an optional rate aimed at providing a residential customer with truly cost-based rates.

318. PSD's proposed three-tier rate achieves the goal of cost-based rates for the proposed TOU-D schedule and is therefore reasonable; however, Edison should be afforded a reasonable period of time to implement the new schedule with that implementation taking effect no later than June 1, 1988.

319. It is reasonable to allocate the estimated revenue deficiency created by TOU-D to all residential customers.

320. Edison's proposed DS schedule coupled with PSD's proposed TOU-D schedule and the parties' agreed limitations on the availability of those schedules provide, to an appropriate level of residential customers, significant options for controlling their energy usage and reducing their electric bills and are therefore reasonable.

321. The customer charge proposed by Edison and PSD for the domestic customer group, while reasonable in concept, would have an inequitable and negative impact on residential customers and would not reflect decremental customer costs.

322. Because of the shortcomings of the proposed customer charge, it is reasonable to continue Edison's minimum base rate charge at $0.10/day and to reject implementation of a customer charge for domestic customers at this time.

323. It is inappropriate to adjust the submetering discount under the DMS-2 schedule to reflect an allowance for distribution energy losses in the absence of a line loss study.

324. It is inappropriate to institute a balancing account for a single cost related to a specific customer group when such accounts are reserved for major proceedings affecting all utility customers.

325. Because it has been demonstrated that submetered mobilehome parks do incur distribution energy losses, it is

reasonable for Edison to undertake a study, in cooperation with WMA, to determine the actual line losses incurred by submetered mobilehome parks to ensure that the costs associated with those losses are properly reflected in the DMS-2 discount.

326. Edison's reliance on its interpretation of Public Utilities Commission Section 739.5 to switch from a levelized to a nonlevelized fixed charge rate in calculating the DMS-2 discount is not a sufficient enough justification to warrant a change which could have serious economic repercussions for the affected customer group.

327. In order to make the change from the use of a levelized to a nonlevelized fixed charge rate in calculating the DMS-2 discount, it is necessary to know specifically whether the levelized fixed charge rate did in fact represent Edison's average costs in prior years; the extent to which those costs were understated or over-stated, if at all, by using a levelized fixed charge rate; and the extent to which it fails to represent Edison's average cost now.

328. It is unlikely that the Legislature intended that, for purposes of determining the DMS-2 ciscount, the utility's average costs were to be developed in isolation for each test year without regard to the manner in which those costs had been determined in prior years.

329. The preceding findings justify the rejection of Edison's attempt to shift from a levelized to a nonlevelized fixed charge rate in this proceeding to calculate the DMS-2 discount.

330. A diversity benefit arises when a master-metered customer is billed more sales at baseline rates and less sales at nonbaseline rates than are actually consumed by his submetered tenants.

331. The need to adjust the submetering discount and charges for domestic master-metered customers to reflect a diversity benefit was recently been recognized by the Commission for PG&E in

D.86-12-091, but the issue is a new one for Edison's mobilehome park customers.

332. The application of a diversity adjustment to correct an inequity to other customers resulting from the billing of submetered mobilehome parks is as necessary for Edison's domestic master-metered schedules as it was for PG&E.

333. The methodology for calculating the diversity adjustment is not yet perfected, Edison having insufficient time to "correct" the errors in PG&E's study and perform a study based on usage patterns of individual mobilehome parks.

334. In the absence of the appropriate study, it is reasonable and equitable to adopt a conservative estimate of the diversity adjustment.

335. WMA's proposed diversity adjustment of $1.58 is a conservative estimate, is similar to the adjustment adopted for PG&E, and is therefore reasonable.

336. It is reasonable to apply the diversity adjustment adopted in this proceeding to reducing the submetered discount, as opposed to base rate charges, under the DMS-2 schedule.

337. To ensure an accurate estimate of the diversity adjustment for Edison's next general rate case, it is reasonable to direct Edison to derive that estimate based on a study which considers the usage patterns of mobilehome parks which it individually meters and the usage related to each master meter.

338. WMA's proposed discount for DMS-2 of $7.82 per space per month or $0.26 per space per day based on a levelized fixed charge rate and absent an allowance for distribution energy losses is reasonable subject if reduced to reflect the adopted diversity adjustment of $1.58 per space per month.

339. The above calculation yields an adopted DMS-2 discount of $6.34 per space per month.

340. A diversity benefit exists with respect to all master-metered customers and it is therefore reasonable to apply such an adjustment to Edison's DM and DMS-1 schedules.

341. A diversity factor of $2.43 for DM and DMS-1 of $2.43 per space per month or $0.08 per space per day for the DM and DMS-1 schedules represents a reduction in Edison's proposed diversity factor for these schedules proportionate with the reduction adopted for Edison's proposed DMS-2 diversity factor and is reasonable.

342. Edison's proposed discount for DMS-1 does not appear to be based on a current study.

343. A DMS-1 discount of $2.41 per space per month or $0.08 per space per day represents an increase in that discount consistent with the increase in the DMS-2 discount and based on an approach which maintains the current ratio between the DMS-1 and DMS-2 discounts and is therefore reasonable.

344. The record in this proceeding includes none of the RV park owners' alternative rate design proposals set forth in their brief.

345. On the basis of the RV park owners having failed to present their specific rate design proposals during the course of hearings in this proceeding and thereby denying other parties and this Commission the opportunity to cross-examine or respond to those proposals, the RV park owners' alternative rate design proposals cannot be considered in this proceeding.

346. Despite this failure, the Commission is not foreclosed from considering the need for tariff changes like those proposed by the RV park owners in the future on the basis of the RV park owners' assertions regarding the residential nature of RV tenants and parks.

347. Before the Commission can consider the application of baseline allowances to RV parks, evidence must be presented which addresses the exact residence requirements to be applied to such parks and their tenants, the need for monitoring, and the

appropriate charges for master-metered and submetered service for RV parks and their tenants.

348. Before a submetering discount similar to that included in the DMS-2 schedule could be applied to RV parks, evidence must be presented on the costs associated with installing, operating, and owning the submetering distribution facilities within the RV park and the propriety of applying the same statutory standards for establishing discounts for RV parks and mobilehome parks.

349. Based on the preceding findings, it is reasonable to direct Edison to conduct a study for its next general rate case of the need for and feasibility for tariff changes extending baseline allowances or master-metered discounts to RV tenants and RV park owners.

350. The agreements reached by Edison and PSD regarding the rate structures of schedules applicable to the small and medium power customer group are for the most part based on sound rate design principles and are reasonable.

351. An exception from the above finding is Edison's and PSD's agreement to "ratchet" the demand charge for small and medium power customers.

352. "Ratcheting" refers to the setting of the demand charge at a percentage of the highest demand over a fixed period of time and has been proposed by Edison in this proceeding for all demand-metered schedules.

353. Based on the findings below which support the removal of "ratchets" proposed for demand charges for the large power customer group, it is similarly not reasonable to adopt Edison's and PSD's ratchet proposal for demand charges under the small and medium power rate schedules.

354. Edison's proposed schedule TC-1 energy rate provides proper price signals based on marginal costs and the customer's usage characteristics and is reasonable.

355. The agreements reached by Edison and PSD regarding the rate structures for the TOU-GS and TOU-GS-SOP schedules are consistent with current rate design policies and are reasonable to the extent that the "ratcheting" of demand charges under these schedules is eliminated and Edison's proposed energy charges for the two schedules are reflected.

356. Conjunctive billing for multiple meters at a single school site, subject to limitations similar to those imposed for PG&E in D.86-12-091, permits schools to realize the benefit of consolidated billing without the need to incur additional costs solely to attain that goal and is equally appropriate for Edison's school customers as it was for those located in PG&E's service territory.

357. To ensure that the benefits of conjunctive billing are realized, it is appropriate to order Edison to offer conjunctive billing for multiple meters at a single school site on an experimental basis consistent with D.86-12-091 and Resolution E-3045, to direct Edison to file an advice letter implementing the necessary forms, and to undertake an evaluation of conjunctive billing for schools and for all customers for its next general rate case.

358. Sufficient justification has not been presented in this proceeding to enlarge the conjunctive billing program for schools to include conjunctive billing for multiple sites.

359. "Ratcheting" of demand charges is as inappropriate for schools as it is for other customer groups.

360. "Unbundled" and time-differentiated rates for schools are adequate to ensure that schools pay those costs reasonably attributable to their usage characteristics without the need to waive non-time-related demand charges.

361. Based on the above finding, it is reasonable to reject SCRUB's recommended waiver of non-time-related demand charges for schools.

362. PSD's proposed TOU-8 subschedules are in keeping with D.84-12-068 in Edison's last general rate case, provide rates related to the cost of service and load characteristics of TOU-8 customers by voltage level, and are reasonable.

363. Edison's and PSD's agreement on TOU-8 demand charges achieves, for the most part, demand charges which are cost-based and load-related and, with the elimination of "ratchets" on those charges, is reasonable.

364. In recent years, the Commission has sought to move away from the concept of ratchets based on the discriminatory effect of such a rate design tool on customer billings among customers with identical usage.

365. The use of ratchets is almost completely at odds with the Commission's efforts to accurately reflect the costs imposed by the customer on a time- and load-related basis.

366. The Commission also does not rule out the possibility that diversity in demand is reflected in non-time-related demand charges over a 12-month period.

367. It is reasonable for the effort to unbundle rates not to be blind to detrimental impacts which may result from such design tools as ratchets.

368. Based on the preceding findings, it is reasonable to reject Edison's and PSD's proposed ratchets on demand-related meters for small, medium, and large power customer rate schedules.

369. To the extent possible each individual rate component should be based on marginal cost, and it is more appropriate to offset adverse rate impacts through rate limiters, rather than to limit demand charges to a certain percentage of their EPMC level.

370. Our finding regarding the impropriety of using the ERI to calculate generation marginal demand costs at this time is equally applicable to our consideration of its use in determining demand charges for TOU-8 customers.

371. It is therefore reasonable not to apply the ERI at this time to the calculation of TOU-8 demand charges, but it is reasonable to require Edison and PSD to examine the issue of its applicability for rate designpurposes in Edison's next general rate case.

372. Edison's proposed off-peak energy charge for TOU-8 is reasonable based on the need for consistency between the TOU-8 and TOU-GS schedules.

373. In developing TOU-8 rates, it is reasonable to develop the interruptible credits on an incurrence, rather than an EPMC, basis.

374. To ensure that subtransmission energy rates are not nominally higher than primary voltage energy rates, it is reasonable to align these rates to be equal.

375. PSD's proposed real-time pricing schedule achieves the program goals of providing more specific price signals than are available under current time-of-use rates and is therefore reasonable.

376. The need for a TOU-8-SOP rate option is clear as a means of providing eligible customers with more accurate price signals and with the opportunity to change existing usage patterns in response to those signals.

377. TOU-8-SOP encourages consumption and increases sales in the off-peak period thereby offsetting any minimum load problem which Edison might experience.

378. PSD's proposed TOU-8-SOP schedule achieves the goals of this schedule while providing an accurate estimate of the number of customers who will migrate from TOU-8 to this new schedule and is therefore reasonable.

379. In this proceeding, issues similar to those presented in our recent decisions involving PG&E's interruptible schedules (D.86-12-091 and Resolution E-3044) have been presented.

380. PSD's proposed I-6 schedule, as modified below, achieves the goal of providing cost-based rates to interruptible customers and is reasonable.

381. The penalty for failure to interrupt or curtail proposed by PSD is too harsh and would act as a significant deterrent to customers moving to this interruptible schedule.

382. The graduated approach for such penalities, as adopted in Resolution E-3044, is sufficient to ensure that an interruptible customer responds to a request by Edison to interrupt without deterring service under this schedule and is therefore reasonable to include in Edison's interruptible schedules.

383. In considering whether existing interruptible schedules I-3 and I-5 should be closed to new customers in the presence of a cost based interruptible schedule (I-6), the Commission must weigh our goal of cost-based rates against the need of interruptible customers to expect consistency in rate design for the term of the contract signed under those schedules (5 years) and the requirements of any applicable statute (i.e., Section 743 of the Public Utilities Code).

384. In balancing these interests, it is reasonable to leave the I-3 and I-5 schedules open for new customers until January 1, 1991, with language included in Edison's tariffs noticing that these schedules will be closed to new customers after that date.

385. In recognition of the reasonable expectations of existing interruptible customers, it is reasonable to permit those customers who had signed a contract with Edison under the I-3 and I-5 schedules prior to the effective date of this decision to complete that contract term under those schedules and to therefore close the I-3 and I-5 schedules for those customers effective January 1, 1993.

386. For new customers signing contracts under the I-3 and I-5 schedules between the date of this decision and January 1, 1991, it is reasonable for the terms of their contracts to provide for their

termination with respect to Schedules I-3 and I-5 no later than January 1, 1993, with the remainder of the unexpired term of those contracts being served under Schedule I-6 to enable Edison to rely on the five-year commitment to interruptible service.

387. Because of their lack of use by interruptible customers, it is reasonable to eliminate Schedule I-4 effective with this decision and to close Schedule I-2.

388. In recognition of the cost-based nature of Schedule I-6 and the fact that the specific interruptible schedule should not alter Edison's ability to rely on that load, it is reasonable to adopt CLECA/CSPG's recommendation to permit I-3 and I-5 customers to move to I-6 at any time conditioned on the unexpired terms of the I-3 and I-5 contracts being completed under I-6.

389. It is reasonable to adopt the two super off-peak interruptible rate options to which Edison and PSD have agreed.

390. It is reasonable to develop credits and penalties under Schedules I-1, I-2, I-3, and I-5 consistent with our discussion in this decision.

391. PSD's proposed interruptible rates, adjusted to reflect our adopted ERI value of 0.43, most accurately reflect the value of interruptibility to Edison and are therefore reasonable.

392. Although the record in this proceeding was not sufficient to warrant a change in calculating interruptible rates to a cost-basis, it is reasonable to direct Edison and PSD to develop interruptible schedules for Edison's next general rate case based on both a cost-of-service approach and a valuation of curtailability methodology to permit the Commission to compare and determine the merits of changing the approach for determining interruptible incentives.

393. Because the 3-Rs Rulemaking (R.86-10-001) is the appropriate forum for determining terms, rates, and sales associated with special contracts and contract rates, it is not reasonable in this proceeding to adopt Edison's proposed generic

special contract schedule, TOU-CR-2, which would properly be presented in the context of R.86-10-001.

394. It is appropriate to authorize the TOU-CR-1 tariff as part of Edison's tariff structure and direct that it be covered by ERAM until such time as a decision in R.86-10-001 separates Edison's customers into an ERAM and a non-ERAM group.

395. The standby charges and terms to which PSD and Edison have agreed, requiring the closing of Schedules SCG 1 through 3 and the establishment of Schedule S, properly result in the uniform treatment of standby customers and other large power customers with similar load, achieve our goal of cost-based rates, and are reasonable.

396. The continued effort to refine and clarify those costs directly imposed on the system by the self-generator in receiving standby service is appropriate.

397. It is unreasonable to "phase-in" rate increases for a single customer group (standby customers), especially when any adverse rate impacts can be more appropriately addressed through rate limiters.

398. The Commission has recognized that the full implementation of cost-based rates can result in severe bill impacts for some customers and that rate limiters provide a reasonable tool for mitigating this result.

399. The rate limiter permits the Commission to address the problems of adverse bill impacts while still ensuring marginal cost-based rates.

400. While the parties, except for PSD with respect to standby rates, did not recommend any specific level for the rate limiter, D.86-12-091 provides a reasonable formula for determining those limiters to mitigate adverse bill impacts at periods of peak demand.

401. Based on D.86-12-091 and PSD's well-supported showing on standby rate limiters, it is reasonable to adopt rate limiters for

TOU-8 and standby customers consistent with our discussion in this decision.

402. It is reasonable to spread the revenue deficiency resulting from the imposition of the adopted rate limiters on an EPMC basis back to all customers receiving service under TOU-8.

403. The rate limiters adopted in this proceeding coupled with the reduction in rates, the use of an EPMC revenue allocation, and the rejection of demand charge ratchets, will provide reasonable and stable rates for TOU-8 customers.

404. Agricultural rates are a continual focus of concern for this Commission which, along with the Legislature, has attempted to provide for rate schedules and options which recognize the significant electrical requirement and diversity in load patterns of this customer group.

405. Edison's proposed placement of citrus growers on the three-phase GS-TP schedule with movement to PA-1 or PA-2 in three years coupled with the citrus growers' proposed amendment of Special Condition 5 of PA-1 when made comparable to special condition 5 for PA-2, permits citrus growers to respond to the changes in rate design adopted in this proceeding while eventually moving to cost-based rates, recognizes load conditions unique to this group of customers, and are therefore reasonable.

406. Customer charges of $10 for PA-1 customers and $20 for PA-2 customers are based on marginal customer costs, reflect the differential in marginal customers costs between these two schedules and are reasonable.

407. The demand charges proposed by Edison and PSD for the PA-1 and PA-2 schedules, modified to reduce the noncoincident demand charge for PA-2 customers and the connect charge for PA-1 customers by one-half to reflect differences in costs imposed by rural, as opposed to urban customers, achieves cost-based rates for the agricultural customer group and are reasonable.

408. The energy charges proposed by Edison and PSD for the PA-1 and PA-2 schedules are based on sound rate design principles and are reasonable.

409. The policy adopted in D.87-04-028 to adopt alternative service options for agricultural customers based on their needs and usage characteristics and the statutory mandate of Section 744 of the Public Utilities Code is equally applicable to Edison.

410. The PSD proposed menu of alternative service options for Edison's agricultural customers is consistent with D.87-04-028, provides a significant number of options for these customers, properly distinguishes between customers based on their demand level, and is reasonable.

411. The mandatory transfer from TOU-8 to the agricultural class of ACWA accounts or other large pumping accounts which meet the standard adopted in D.87-04-028 of customers for whom at least 70% of the water pumped by an individual account is for agricultural purposes provides appropriate service options for these agricultural customers and time periods narrower than those currently available under TOU-8 and is reasonable.

412. Based on the above finding, it is unnecessary to adopt the PA-TOU option proposed by ACWA.

413. It is reasonable to permit Edison to implement the new agricultural tariff options no later than June 1, 1988 due to the need to inform customers of the changes and install required metering.

414. It is reasonable to direct Edison to conduct, in cooperation with PSD, workshops to explain and refine the agricultural tariff options adopted in this decision.

415. Our inclusion of streetlighting, with respect to the energy component of streetlighting charges, and streetlighting marginal customer costs in the revenue allocation process are a recognition that these customers, despite unique traits, also share characteristics common to all other Edison customers.

416. Streetlighting customers, like other customers, can benefit from rates which reflect the costs which these customers impose on the utility system.

417. Edison's cost of service study performed for this proceeding is responsive to the Commission's directive in D.84-12-068 and is reasonable.

418. It was appropriate for purposes of its cost of service study for Edison to rely on a Replacement Cost New methodology in the absence of adequate records upon which Edison could base an Original Cost Less Depreciation or historical cost analysis.

419. Edison's reliance on the TOU-GS schedule to calculate streetlight energy charges is misplaced and is a substantial departure from our policies emphasizing rates based on customer-imposed costs and use characteristics.

420. PSD's proposed energy and demand charges for streetlighting are based on marginal costs, reflect unallocated revenue, and are reasonable.

421. Having reflected marginal customer costs in revenues allocated to the streetlighting customer class based on a TMS (transformer, meter, service drop) approach, it is unnecessary to include an MDS (minimum distribution system) charge in streetlight rates.

422. PSD's proposed customer charges for streetlighting based on marginal customer costs are reasonable.

423. PSD's proposed streetlight facilities charges, modified to reflect its agreement with Edison of a $1.00 per lamp per year transformer charge on Edison-owned lamps, are based on the cost of those facilities at the margin, a Reproduction Cost New approach, and PSD's partial inclusion of the RO transformer and are therefore reasonable.

424. Edison's proposed rate design for streetlighting complies with our order in D.84-12-068, achieves the goal of reflecting "unbundled" rates, and is reasonable.

425. The diversity in a streetlight customer's mix of lamps and low off-peak usage should mitigate any adverse rate impacts resulting from this order, and a rate limiter for streetlight charges is therefore unnecessary.

426. The proposed charges and rate structures to which Edison, PSD, and CAL-SLA agreed are reasonable.

427. For consistency in the methodology used to calculate streetlight rates, it is appropriate to rely on marginal costs to develop the customer account expense and to adopt a rate of $.12058 per lamp per month.

428. Edison's proposed cable and photocontroller charges for the DWL schedule are reasonable.

429. Based on current installation practices, CAL-SLA's Special Condition 2 for the LS-2 and LS-3 conditions is reasonable.

430. To achieve consistency with current manufacturers specifications, it is appropriate to adopt CAL-SLA's proposed language for Special Conditions 10 and 12 of the LS-2 schedule.

431. For the protection of those streetlight customers who rent streetlights from Edison, for which equipment Edison is ultimately responsible, it is reasonable to retain the current Special Condition 3 of Schedule LS-2.

432. To ensure the appropriate recovery of revenue related to Edison's optional time-of-use meters, it is reasonable to reflect the following estimate costs of those meters in the adopted results of operation: $369,500 in 1988; $1,012,600 in 1989; and $1,559,800 in 1990.

433. PSD's proposal with respect to adjustments in rate components due to revenue requirement changes occurring between general rate cases is based on increasing demand and customer charges toward their EPMC relationships for revenue requirement increases and holding them constant for decreases.

434. PSD's proposed rate design for revenue requirement changes occurring between general rate cases is consistent with our adopted rate design policies and is therefore reasonable.

<u>Conclusions of Law</u>

1. Escalation rates for labor of 3.5% in 1987 and 1988 and non-labor of 2.99% in 1987 and 4.41% in 1988 are reasonable.

2. The sales forecast shown in the table Summary of Kilowatt-Hour Sales on page 8 of this decision is reasonable.

3. CLMAC revenues should not be included in the adopted present rate revenues.

4. The present rate revenues shown in Appendix C are reasonable.

5. Edison has not provided adequate justification for its requested increase in steam generating unit overhaul expense.

6. A seven-year average of steam generating unit overhaul expense is reasonable.

7. A three year interval for low pressure turbine rotor repairs is reasonable.

8. A test year hydro production expense of $20.5 million and a test year other production expense of $17.2 million are reasonable.

9. The level of SONGS production expense agreed to by Edison and PSD is reasonable.

10. SONGS O&M expense should not be relitigated in SDG&E's general rate case.

11. SDG&E should be authorized to reflect in future base rate filings the level of SONGS O&M expense, adjusted for inflation, adopted in this decision.

12. Edison should be authorized to reflect an increase in NRC fees in its attrition filing.

13. A flexible refueling schedule is reasonable for SONGS and Palo Verde.

14. Edison's estimate of Palo Verde O&M expense, including refueling outage expense, is reasonable.

15. Edison should reflect in A.87-08-054 the level of O&M and refueling expenses found reasonable in this decision for Palo Verde 3.

16. Edison should submit in its next general rate case filing a comparative study that can be used to develop a zone of reasonableness for nuclear O&M expense.

17. Recovery of a one-time expense for a chemical cleaning process at SONGS 3 over three years is reasonable.

18. Recovery of $2.9 million for expenses previously incurred for the reprocessing of spent nuclear fuel from SONGS 1 without Commission approval of the expenses or a tracking mechanism is inappropriate.

19. A test year transmission expense of $75.3 million is reasonable.

20. PSD's $3.5 million reduction to Edison's estimate for account 582 reflects recorded downward trends in labor expense and is reasonable.

21. It is reasonable to reflect Edison's transition to contract labor for tree trimming in account 583.

22. It is reasonable to reflect the accounting change for purchases of meter locking rings in account 597.

23. Edison's estimated cost for its three-year underground inspection program is reasonable.

24. Edison should provide in its next general rate case filing data on the percent of underground switch failures per year and the age of failed switches.

25. A five-year average of storm damages is reasonable.

26. Edison has not provided adequate justification for its estimated cost of providing termination notices to customers.

27. A $450,000 reduction in Edison's estimated cost for providing termination notices to customers is reasonable.

28. Edison's 1986 savings of $225,000 from participation in Enercom should be included in the calculation of its uncollectible rate.

29. An uncollectible rate of .214% and a franchise tax rate of .73% are reasonable.

30. Edison should adjust its annual energy, ECAC, and MAAC rates, effective January 1, 1988, to reflect the uncollectible and franchise tax rates adopted in this decision.

31. Edison should be authorized to reflect an increase in postage expense in its attrition filing.

32. It is reasonable to limit the growth from 1985-1988 in A&G expense items over which Edison has control to 8%, the expected customer growth from 1985-1988.

33. The adopted expense level for account 930 reflects the amortization of expenses due to the abandonment of the Ivanpah project.

34. A 10% reduction in Edison's estimated cost of general insurance, comprehensive general liability insurance, and directors and officers insurance is reflective of market trends and should be adopted.

35. PSD's estimated cost of group life insurance is reasonable.

36. PSD's estimated cost of outside provider medical costs adjusted for employee growth is reasonable.

37. The Superfund Tax should be used as a deduction for calculating income taxes.

38. It is reasonable to reflect the provisions of the Federal Tax Reform Act of 1986 in calculating income taxes.

39. Edison's estimated 1988 plant-in-service is reasonable.

40. The depreciation rates agreed to by Edison and PSD are reasonable.

41. The guidelines for evaluating PHFU are reasonable and should be adopted.

42. The Evaluation and Compliance Division should notify all energy utilities under CPUC jurisdiction that we expect guidelines for evaluating PHFU to be addressed in their next general rate case.

43. Reductions in Edison's estimates of PHFU of $7.5 million for 1988 and $16.2 million for 1989 are reasonable.

44. This proceeding should remain open to consider any changes in the calculation of working cash allowance adopted in A.86-12-050.

45. The method of calculating attrition agreed to by Edison and PSD is reasonable.

46. The 1989 ERAM base level should be increased by $9.8 million to reflect a decrease in FERC sales.

47. Edison should be allowed to include the SONGS 2 chemical cleaning expense in its attrition filing for 1990.

48. The impact of Edison's optional TOU meter plan should be reflected in calculating attrition.

49. Edison should use the format shown in Appendix D to develop its attrition filings.

50. Edison's capital structure as revised in the September update hearings is reasonable.

51. An incremental cost of long-term debt of 9.68% is reasonable.

52. PSD's forecast of tax-exempt financing is reasonable.

53. Edison should be authorized to recover the costs associated with perpetual securities.

54. A ROE of 12.75% is reasonable and should be adopted.

55. Edison's MAAC rates for SONGS 2 and 3 post-commercial operating costs, pre-commercial operating costs for Palo Verde, and Section 463 projects should, effective January 1, 1988, reflect an ROE of 12.75%.

56. Carrying costs on nuclear fuel inventory and coal inventory should be calculated using Edison's ECAC interest rate and recorded in the ECAC account.

57. Recovery of $2.4 million for expenses previously incurred for Palo Verde affirmative case costs without Commission approval of the expenses or a tracking mechanism is inappropriate.

58. Edison should provide, coincident with its fall 1988 resource plan, value-based reliability criteria and a comprehensive study evaluating the range of alternative uses for its aging oil and gas generating units. These should be designed to address PSD's concerns as stated in Exhibit 53.

59. Edison should be authorized to request funding for plant modification or two-shifting to reduce minimum generation capability at certain oil and gas generating units.

60. A cost cap of $80.0 million for Edison's share of the DC Expansion is reasonable.

61. The proposed procedure, attached as Appendix A, which provides for modification of Edison's MAAC to include the recorded investment-related revenue requirement and the recorded revenues related to specific plant additions estimated to cost more than $50 million is reasonable and should be adopted.

62. Edison should be authorized to file for an increase in the MAAC rate, subject to refund, equal to 75% of the annualized investment-related revenue requirement for the DC Expansion, and Devers-Palo Verde projects. Edison's filing should be by an advice letter submitted after each project becomes commercially operational.

63. Edison should file an application to determine the reasonable and prudent costs of the Balsam Meadow, Devers-Valley-Serrano, DC Expansion, and Devers-Palo Verde projects not later than six months after the final portion of each project is placed in-service.

64. Edison's MAAC revenue requirement should be increased by $73.7 million for Devers-Valley-Serrano and Balsam Meadow and the MAAC rate should be increased by $55.3 million or 0.085 cents/kWh, subject to refund.

65. PSD's motion to set aside submission of the DC Expansion project should be denied.

66. Edison failed to disclose the existence of a letter agreement with LADWP, that could impact the cost-effectiveness analysis of the DC Expansion project and link it with other transmission projects.

67. PSD's motion to compel the production of the documents, attachment 6 to the motion, should be granted.

68. The cost-effectiveness analysis of the DC Expansion project and the adopted cap should be reviewed in conjunction with our analysis of Edison's other transmission projects and/or the agreements with LADWP.

69. In order to insure consistent ratemaking treatment, SDG&E's portion of SONGS O&M expenses billed to it by Edison should be reflected in future SDG&E base rate changes at the level adopted by this order adjusted for inflation.

70. Edison's requested funding for the competing for the customer RD&D program is reasonable.

71. Edison's requested funding for the electric transportation RD&D project should be reduced to $100,000 for monitoring the work of others.

72. Edison should be authorized to spend $900,000 on its alternate fuels, occupational and community safety, and advanced energy conversion RD&D programs.

73. Edison's natural resources management RD&D program should not be funded.

74. Edison's actual 1988 EPRI dues of $14.7 million should be authorized in rates.

75. Edison should emphasize long-term, end-use RD&D that is consistent with its resource plan and coordinated with other California utilities and experienced research organizations.

76. Edison should allocate $1 million from its RD&D budget to the Institute (CIEE) for long-range end-use energy research.

77. All RD&D program expenditures should be recorded in account 930.2.

78. A one-way balancing account for RD&D expenditures should be adopted.

79. All expenditures on RD&D program changes should be removed from the one-way balancing account, retroactively, if found unreasonable in a subsequent proceeding.

80. A productivity gain of approximately 2.75% for 1988 is reasonable.

81. Edison and PSD should jointly develop a data base for use in evaluating employee compensation in Edison's next general rate case.

82. Edison's and PSD's agreement on ratemaking treatment for gains on sales of utility assets to affiliates, net income of utility-related subsidiaries and markup for services provided by the utility is reasonable and should be adopted.

83. PSD's recommended royalty to be paid by affiliates on gross revenues should not be considered in this decision.

84. PSD's hazardous waste management recommendations are reasonable and should be adopted as modified below.

85. PSD's recommendations concerning manufactured gas hazardous waste sites should be expanded to include all hazardous waste sites included in Edison's general rate case filing and/or its annual hazardous waste management report.

86. Edison should be allowed to combine the two different annual hazardous waste reports PSD recommends into one annual report.

87. Long-term goal setting, verification procedures, and annual reporting for utility F/MBE programs should be addressed in R.87-02-026.

88. Edison had a significant increase in the amount and number of its contract awards to F/MBEs from 1984-1986.

89. Edison should achieve significant increases in the amount and number of contract awards to F/MBEs for future proceedings.

90. Ethics and fairness dictate that an extension to file a brief granted to one, but not all, parties to a proceeding should not be used as an opportunity to respond to briefs which were timely filed.

91. Edison should continue to promote reasonable and cost-effective conservation measures and efficiency options for its customers.

92. To ensure its continued cost-effectiveness, Edison should closely monitor its Thermal Energy Storage program in coming years through the reporting requirements established in Resolution E-3053 and the establishment, for accounting and reporting purposes, of the categories of Load Shifting (Medium/Small and Large Customer) and Load Retention (Medium/Small and Large Customer).

93. Edison should be directed to continue its efforts to quantify the gas-side impacts of its Thermal Energy Storage program consistent with the recently reused Standard Practice Manual for Economic Evaluation of DSM Programs.

94. To ensure the continued cost-effectiveness of its Water Storage Program, Edison should undertake whatever reasonable cost-cutting measures are possible to limit any unnecessary and non-cost-effective spending.

95. Funding for Edison's Residential and Non-Residential Marketing programs should be deferred until further analysis of the marketing issue is undertaken in the 3-Rs Rulemaking, R.86-10-001.

96. Edison should develop the reports required for its demand side management programs using the same guidelines adopted for PG&E in D.86-12-095 at pages 111 through 118.

97. The generic demand side management definitions being established in the Reporting Requirements Manual should be used by Edison in all future rate case, offset, and advice letter filings.

98. The funding levels found reasonable in this decision for Edison's demand side management programs should be adopted with an overall funding level of $54,194,000.

99. All demand side management program funding should be consolidated and placed in base rates starting with the test year 1988, with the exception of certain TES incentive payments as described in our discussion.

100. Edison should continue to be allowed to make funding shifts of $2.5 million within the three major demand side management categories without an advice letter, but with notice to the Commission's Evaluation and Compliance Division.

101. Edison should be required to file an advice letter for funding shifts between the three major demand side management program categories or for shifts of greater than $2.5 million within those categories.

102. Edison should continue the effective development of QF resources.

103. The overall funding for Edison's Cogeneration/Small Power Production Program of $1,765,000, with reductions of $200,000 in 1989 and $550,000 in 1990, if warranted on the basis of a periodic analysis to be undertaken by Edison and PSD, found reasonable in this proceeding should be adopted.

104. The results of operation as set forth in Appendixes C and D are reasonable and should be adopted.

105. Based on the foregoing findings and conclusions a $48.5 million decrease in Edison's base rate revenues is just and reasonable and should be adopted.

106. The Commission's findings in this general rate case on issues related to marginal cost, revenue allocation, rate design, and demand side management programs should take into consideration the policies adopted in R.86-10-001 to address the problem of uneconomic bypass.

107. Marginal costs should continue to be the basis for the revenue allocation and rate design adopted in this proceeding.

108. In the future general rate cases, ECAC proceedings, or other proceeding designated by A.82-04-44, et al., of Edison, PG&E, and SDG&E, all parties presenting testimony requiring the use of a production simulation model to develop marginal or avoided costs should provide a "base case" run using the ELFIN model.

109. To ensure access by all parties to input assumptions and data related to cumputer models used to calculate a utility's IERs, a workshop should be held no later than one week following the filing of testimony by either Edison, PG&E, or SDG&E in their respective ECACs, general rate case proceedings, or other proceeding designated by A.82-04-44, et al. for updating IERs.

110. The purpose of the workshop referenced in the preceding conclusion should be (1) to determine the data sets, resource plans, load shape, heat rate input, unit commitment and dispatch, minimum load conditions, resource assumptions, marginal fuel assumptions, and all other pertinent data which the utility has used to calculate its IER and (2) to provide a forum in which agreements between the parties can be reached.

111. Two IERs should be adopted in this proceeding, one for use in the calculation of marginal energy costs and one for use in the calculation of avoided energy costs, based on methodologies which reflect the differences in these two costs.

112. The annual IERs found reasonable in this decision should be adopted and should remain in effect until updated as prescribed in A.82-04-44 et al.

113. In the calculation of IERs, the adjustment of the ELFIN model to reflect start-up and no-load costs should be reduced in the amount of any double-counting of these costs.

114. The input assumptions used in calculating marginal and avoided energy costs found reasonable in this decision should be adopted.

115. The undisputed portions of PSD's and Edison's joint exhibit on marginal energy costs and Edison's undisputed changes to factors used in the calculation of avoided energy costs should be adopted except as otherwise modified by this decision.

116. The marginal energy costs and avoided energy costs found reasonable in this decision should be adopted.

117. The generation and transmission marginal demand costs found reasonable in this decision should be adopted.

118. To determine the applicability of the ERI for calculating generation marginal demand costs and for determining demand charges used in rate design, Edison and PSD should be directed to examine this issue in Edison's next general rate case.

119. An ERI based on an EUE target should be used as the basis for adjusting the value of the combustion turbine used as a proxy for avoided capacity costs.

120. An ERI adjustment factor of 0.43 should be adopted for 1988 and should remain in effect until updated or revised as prescribed in A.82-04-44, et al.

121. The issue of the reinstatement of Standard Offer 2 should be decided in A.82-04-44, et al.

122. Marginal customer costs should be included in the revenue allocation process, should be based on the weighted average of incremental and decremental customer costs, and should include the customer-related costs associated with meters, service drops, final line transformers, access equipment replacement and improvement, and distribution equipment directly assignable to a customer class.

123. In the absence of a "fully developed estimate" of incremental and decremental costs in this proceeding, PSD's incremental cost estimate based on the TSM (transformer, service drop, and meter) approach, exclusive of final line transformers for all customer classes, should serve as the proxy for the weighted average method in this proceeding.

124. In future general rate cases, all parties should base their recommendations and numerical estimates of marginal customers costs on the weighted average of the utility's incremental and decremental customer costs.

125. Streetlighting marginal customer costs as calculated by PSD should be included in the revenue allocation process.

126. Edison and PSD should be directed to undertake analyses and record-keeping aimed at identifying all costs to be included as marginal customer costs.

127. The marginal customer costs and marginal distribution costs found reasonable in this decision should be adopted.

128. The marginal cost time-of-use periods found reasonable in this decision should be adopted.

129. A revenue allocation based on an Equal Percent of Marginal Cost (EPMC) approach should be adopted based on moving 1/3 of the way to EPMC in the test year 1988, with a cap for all customer and rate groups of 5% on increases over the system average percentage change.

130. Because the intent of this decision is to achieve a full EPMC revenue allocation for Edison by 1990, this intent should be reflected in any revenue allocation proposed for Edison in 1989 and 1990.

131. Edison's ECAC proceeding should be the forum for considering any adjustments of Edison's inter-class revenue allocation in 1989 and 1990, but this consideration should not include the relitigation of the marginal cost structure and levels adopted in this proceeding.

132. For revenue changes occurring between general rate cases, a system average percentage change revenue allocation approach should be applied to rate increases or decreases occurring between this rate case and Edison's 1989 ECAC, with the revenue allocation for intervening offset filings made after that time to be determined in Edison's 1989 and 1990 ECAC proceedings.

133. Rate adjustments of less than 1% occurring between general rate cases should be allocated on an equal cents per kWh basis.

134. Intra-class revenue allocation should be developed on an equal percent of present rate revenues for Edison's small and medium power group, except for TOU-GS and GS-2 which should be based on PSD's and Edison's agreed billing determinants, and on an EPMC basis for Edison's large power customers.

135. Any revenue shortfall resulting from the implementation of new agricultural rate options should be allocated equally among all agricultural rate schedules.

136. Edison should be directed to collect the data necessary to achieve an EPMC revenue allocation for its agricultural and small and medium power customers for its next general rate case.

137. Streetlight energy charges, but not facilities charges associated with an end-use, should be included in the revenue allocation process.

138. Any contract rate revenue deficiency should not be included in the revenue allocation process.

139. The total revenue requirement adopted for Edison as of January 1, 1988, should be included in the revenue allocation adopted in this decision.

140. The rate structures adopted for Edison's rate schedules should reflect, to the extent possible and practical, cost-based rates designed to provide accurate and understandable price signals to which the customer can respond, to reflect a customer's usage

patterns and characteristics, to recover the customer group's revenue requirement, and to mitigate any negative bill impacts.

141. The Commission should consider previous recent decisions relating to the rate design of other utilities as a means of identifying current Commission rate design policy; determining whether that policy is to be continued,modified, or abandoned; and ensuring, to the extent possible, consistent treatment of all ratepayers.

142. The baseline quantities and allocations proposed by Edison and PSD should be adopted.

143. Edison's and PSD's requested implementation of a customer charge for domestic customers should be rejected at this time, and Edison's minimum charge for this customer group should be retained.

144. Edison should be directed to undertake a study, in cooperation with WMA, for its next general rate case to determine the actual line losses incurred by submetered mobilehome parks served under Edison's DMS-2 schedule.

145. A diversity adjustment should be adopted for all of Edison's domestic master-metered schedules.

146. Edison should be directed to conduct a study for its next general rate case of usage patterns of mobilehome parks which it individual meters and the usage related to each master meter as the basis for developing a diversity adjustment.

147. Edison should be directed to conduct a study for its next general rate case of the need and feasibility of tariff changes extending baseline allowances or master-metered discounts to RV tenants and RV park owners.

148. Edison should be required to file an advice letter implementing conjunctive billing for schools with multiple meters at a single site on an experimental basis consistent with D.86-12-091 and Resolution E-3045 and to undertake an evaluation for its next general rate case of conjunctive billing for schools and for all customers.

149. Edison and PSD should be directed to develop interruptible schedules for Edison's next general rate case based on both a cost-of service approach and a valuation of curtailability methodology.

150. If necessary, rate limiters should be used to address the problem of adverse bill impacts in order to preserve marginal cost-based rates.

151. Edison should be directed to conduct, in cooperation with PSD, a workshop to explain and seek refinements to the new agricultural rate options adopted in this decision.

152. The rate structures and charges found reasonable in this decision for each of Edison's rate schedules should be adopted.

153. PSD's proposed rate design for revenue requirement changes occurring between general rate cases based on increasing demand and customer charges toward their EPMC relationships for revenue requirement increases and holding them constant for decreases should be adopted.

154. The TOU-D tariff option and the new agricultural tariff options should be implemented by Edison no later than June 1, 1988.

155. The increases in rates and charges authorized by this decision are justified, and are just and reasonable.

INTERIM ORDER

IT IS ORDERED that:

1. Southern California Edison Company (Edison) is authorized and directed to file with this Commission, on or after the effective date of this order, and at least 3 days prior to their effective date, revised tariff schedules for electric rates as set forth in Appendix I.

2. The revised tariff schedules shall become effective on or after January 1, 1988 and shall comply with General Order 96-A. The revised tariffs shall apply to service rendered on or after their effective date.

3. All transcript corrections received are incorporated in the record.

4. Edison is authorized to file attrition adjustments for 1989 and 1990 based on the results of operation adopted in Appendix C and D.

5. Edison shall provide in its next general rate case filing data on the percent of underground switch failures per year and the age of failed switches.

6. Edison is authorized to include in its attrition filings increases in postage expenses and Nuclear Regulatory Commission fees.

7. Edison shall adjust its ERAM effective January 1, 1989 to reflect full implementation of the guidelines for plant held for future use contained in Appendix B. The guidelines shall apply to all plant held for future use regardless of the acquisition date.

8. Edison is authorized to increase its MAAC revenue requirement by $73.7 million and its MAAC rate by $55.3 million or 0.085 cents/kWh, subject to refund, for the Devers-Valley-Serrano and Balsam Meadow projects.

9. Within six months from the date of this order Edison shall file an application to establish the reasonable and prudent

level of recorded costs of the Devers-Valley-Serrano and Balsam Meadow projects.

10. The procedures set forth in Appendix A for proposed projects in excess of $50 million are reasonable and shall be adopted.

11. Edison is authorized to file for MAAC increases, subject to refund, for the DC Expansion and Devers-Palo Verde projects in accordance with the adopted procedures in Appendix A.

12. Edison shall produce the documents requested by PSD in attachment 6 to its motion within 10 days from the effective date of this decision.

13. Edison shall file a cost-effectiveness analysis of the DC Expansion project and the adopted cap in A.85-12-012 for review in conjunction with our analysis of Edison's other transmission projects and/or the agreements with LADWP.

14. A.86-12-047 shall remain open to consider the impact of a final decision on working cash allowance in A.85-12-050.

15. The Commission's Evaluation and Compliance Division shall notify the energy utilities we regulate that guidelines for evaluating plant held for future use shall be considered in their next general rate case.

16. Edison shall file as set forth in this order an annual report describing its hazardous waste effort, including its underground storage program. The report shall include the information described in Exhibit 65-A.

17. Edison is authorized to file an application(s) as discussed in this order to receive prior approval for funding its hazardous waste program.

18. Edison is authorized to file for funding plant modifications or two-shifting to reduce its minimum generation capability.

19. Coincident with its fall 1988 resource plan, Edison shall provide value-based reliability criteria and a comprehensive study

evaluating the range of alternative uses for its aging oil and gas generating units.

20. Edison is authorized and directed to reflect the adopted return on equity from this order in its MAAC revenue requirement, effective January 1, 1988.

21. Edison is authorized and directed to reflect the adopted franchise tax and uncollectible rates from this order in its MAAC, ECAC, and AER rates, effective January 1, 1988.

22. Edison is authorized to reflect in its ECAC account the carrying costs associated with nuclear fuel inventory and coal inventory, based on the ECAC interest rate.

23. SDG&E is authorized to reflect in future base rate filings the level of O&M expenses for SONGS, adjusted for inflation, adopted by this order.

24. Edison shall provide a comparative study in its next general rate case filing which establishes a zone of reasonableness for nuclear O&M expense.

25. Edison shall establish a one-way balancing account for recording RD&D expenditures.

26. Edison and PSD shall jointly develop a data base for use in evaluating employee compensation in Edison's next general rate case.

27. Edison shall continue to closely monitor its Thermal Energy Storage Program by meeting the reporting requirements established in Resolution E-3053 and the establishment, for accounting and reporting purposes of the categories of Load Shifting (Medium/Small and Large Customer) and Load Retention (Medium/Small and Large Customer) and shall continue its efforts to quantify the gas-side impacts of this program consistent with the recently reused Standard Practice Manual for Economic Evaluation of Demand Side Management Programs.

28. Edison is authorized to offer an incentive under its Thermal Energy Storage program limited to $200/kW.

29. Edison's shall develop the reports required for its demand side management programs using the same guidelines adopted for the Pacific Gas and Electric Company (PG&E) in D.86-12-095 and the Reporting Requirements Manual being developed in response to that order.

30. Edison shall use the generic demand side management definitions being established in the Reporting Requirements Manual in all future rate case, offset, and advice letter filings.

31. Edison is authorized to consolidate all demand side management program funding in base rates beginning with test year 1988 with the exception that all TES incentive payments related to contracts executed prior to January 1, 1988, shall continue to be reflected in the ERAM balancing account consistent with D.82-12-055.

32. Edison is authorized to make funding shifts of $2.5 million within the three major demand side management categories (Residential Conservation, Commercial/Industrial/Agricultural Conservation, and Load Management) without an advice letter, but with notice of the change to the Commission's Evaluation and Compliance Division.

33. Edison shall file an advice letter for funding shifts between the three major demand side management categories or for shifts of greater than $2.5 million within those categories.

34. Periodic analysis on the optimal funding of Edison's Cogeneration/Small Power Production Program shall be undertaken by PSD and Edison, with the first report to be completed on August 31, 1988, to determine whether reductions in program funding of $200,000 in 1989 and $550,000 in 1990 are warranted.

35. All parties to the future general rate cases, ECAC proceedings, or other related proceeding identified in A.82-04-44, et al., of Edison, PG&E, and San Diego Gas and Electric Company (SDG&E) presenting testimony relying on or requiring the use of a production simulation model to develop marginal or avoided costs

shall provide a "base case" run using the ELFIN production cost model. A party to these proceedings may also present testimony using its production cost model of choice, which may differ from ELFIN, and explain the basis for its preference of that model and the results which it produces.

36. In the future general rate cases, ECAC proceedings, or other related proceeding identified in A.82-04-44, et al., of Edison, PG&E, and SDG&E, workshops shall be held no later than one week following the filing of the utility's testimony in those proceedings. The purpose of this workshop shall be to determine the data sets, resource plans, load shape, heat rate input, unit commitment and dispatch, minimum load conditions, resource assumptions, marginal fuel assumptions, and all other pertinent data which the utility used to calculate its Incremental Energy Rate (IER). In addition to data gathering, this workshop shall also serve as a forum in which the parties can agree, to the extent possible, on the assumptions to be used and the appropriate source of those assumptions. The Director of the Commission's Advisory and Compliance Division shall appoint a final arbiter of disputes relating to the achievement of a common data set.

37. Edison and PSD shall present testimony in Edison's next general rate case on the applicability of the ERI to calculations of generation marginal demand costs and to determinations of demand charges used in rate design.

38. For the general rate cases of each electric utility, all parties shall base their recommendations and numerical estimates of marginal customer costs on the weighted average of the utility's incremental and decremental customer costs.

39. With respect to the determination of marginal customer costs, Edison and PSD shall undertake the following for Edison's next general rate case: (1) establish record-keeping that will clearly identify customer hook-up costs and distinguish new from existing customers, (2) analyze non-dedicated distribution

equipment for access versus demand function, and (3) identify replacement and upgrading costs for access equipment.

40. Edison's ECAC proceeding shall be the forum for considering any adjustments of Edison's inter-class Equal Percent of Marginal Cost (EPMC) revenue allocation in 1989 and 1990. This consideration shall not include the relitigation of the marginal cost structure and levels adopted in this proceeding.

41. For rate changes occurring between this rate case and Edison's 1989 ECAC proceeding, Edison shall propose rate schedules showing changes by both EPMC and the system average percentage change. The revenue allocation approach to be applied to Edison's intervening offset filings made after Edison's ECAC proceedings for the 1989 and 1990 periods shall be identified in those proceedings.

42. For its next general rate case, Edison shall collect the data necessary to achieve an intra-class EPMC revenue allocation for Edison's small light and power and agricultural rate schedules.

43. Edison shall undertake, in cooperation with WMA, a study for its next general rate case to determine the actual line losses incurred by submetered mobilehome parks served under Edison's DMS-2 schedule.

44. Edison shall conduct a study for its next general rate case of usage patterns of its domestic master-metered customers which it individually meters as the basis for developing a diversity adjustment of the submetered discount or rates applicable to those customers.

45. Edison shall conduct a study for its next general rate case of the need and feasibility of tariff changes extending baseline allowances or master-metered discounts to recreational vehicle (RV) tenants and RV park owners. Any standards proposed by Edison should take into account Edison's ability to objectively judge and realistically monitor the status of the RV tenant.

46. Edison shall file an advice letter implementing conjunctive billing for schools with multiple meters at a single

site on an experimental basis. This filing shall provide tariffs or forms based consistent with D.86-12-091 and Resolution E-3045 in which PG&E was authorized to offer conjunctive billing to schools. Edison shall also conduct a study for its next general rate case evaluating conjunctive billing for schools and for all customers.

47. Edison and PSD shall propose interruptible schedules for Edison's next general rate case based on both a cost-of-service approach and a valuation of curtailibility methodology.

48. The Commission shall direct, at a date to be set, that a workshop be held by Edison, in cooperation with PSD, to explain and consider refinements to the new agricultural tariff options adopted in this order.

This order is effective today.

Dated December 22, 1987, at San Francisco, California.

STANLEY W. HULETT
President
DONALD VIAL
FREDERICK R. DUDA
G. MITCHELL WILK
JOHN B. OHANIAN
Commissioners

I CERTIFY THAT THIS DECISION WAS APPROVED BY THE ABOVE COMMISSIONERS TODAY.

Victor Weisser

Victor Weisser, Executive Director

AB

APPENDIX A

JOINT EXHIBIT OF PUBLIC STAFF DIVISION
AND SOUTHERN CALIFORNIA EDISON COMPANY
CONCERNING PROCEDURE TO IMPLEMENT
CALIFORNIA PUBLIC UTILITIES CODE SECTION 463
THROUGH THE COURSE OF THE
GENERAL RATE CASE PROCEEDING
BASED ON ADMINISTRATIVE LAW JUDGE'S RULING,
DATED MAY 5, 1987

June 1987

APPENDIX A

JOINT EXHIBIT OF PUBLIC STAFF DIVISION
AND SOUTHERN CALIFORNIA EDISON COMPANY CONCERNING
PROCEDURE TO IMPLEMENT
CALIFORNIA PUBLIC UTILITIES CODE SECTION 463
THROUGH THE COURSE OF THE
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JOINT EXHIBIT OF PUBLIC STAFF DIVISION AND SOUTHERN CALIFORNIA EDISON COMPANY CONCERNING PROCEDURE TO IMPLEMENT CALIFORNIA PUBLIC UTILITIES CODE SECTION 463 THROUGH THE COURSE OF THE GENERAL RATE CASE PROCEEDING BASED ON ADMINISTRATIVE LAW JUDGE'S RULING, DATED MAY 5, 1987

I

INTRODUCTION

A. Purpose

The purpose of this joint Public Staff Division ("PSD") and Southern California Edison Company ("Edison") exhibit is to: (1) set forth a procedure which enables the Commission to consider the reasonableness issues related to additions to Edison's plant which are estimated to cost more than $50 million without the time constraints imposed by the General Rate Case Plan, while allowing Edison to ultimately recover the revenue requirement found reasonable by the California Public Utilities Commission ("Commission") after a reasonableness review, and to recover, on an interim basis and subject to refund, in current rates 75 percent of the estimated revenue requirement for such plant additions prior to the completion of the reasonableness review; (2) propose certain modifications to Edison's tariffs to implement the proposed procedure; and (3) provide the basis for the Commission to implement the proposed procedure in its decision in this proceeding, including the proposed procedure and interim rate relief.

B. Summary

The proposed procedure provides for the modification of the existing Major Additions Adjustment Clause ("MAAC") procedure to include recorded investment-related revenue requirement 1/ and the recorded revenues related to additions to Edison's plant which are estimated to cost more than $50 million. The procedure will apply when such plant is to be reflected in rates for the first time, and is eligible for inclusion in MAAC. Specifically, PSD and Edison propose that:

- o Plant additions to be included in the MAAC will be determined through the general rate case proceeding;
- o The in-service criteria for each project to be included in the MAAC will be determined in the general rate case proceeding;

1/ The term "investment-related revenue requirement" is defined as the sum of (1) depreciation; (2) *ad valorem* taxes; (3) taxes based on income, including any appropriate tax adjustments; and (4) return on California jurisdictional rate base as set forth in the applicable tariff.

- The initial investment-related revenue requirement and resultant

  MAAC rates for each project will be determined in the general rate case proceeding. The MAAC rate level shall be equal to 75 percent of the revenue requirement which is to reflect the utility's estimated investment-related costs or the Commission's adopted cost cap level, whichever is less;

- The noninvestment-related expenses associated with each project shall be determined in the general rate case and reflected in base rates through the general rate case;

- A separate advice letter filing will be made to place each project into the MAAC on its in-service date;

- The previously determined MAAC rate changes for a project will be implemented at the next regularly scheduled Energy Cost Adjustment Clause ("ECAC") or base rate level change after its in-service date to minimize the number of rate changes occurring during the year;

- Between the in-service date of a project and the implementation of MAAC rates reflecting that project, all recorded investment-related revenue requirement associated with that project shall be recorded as an undercollection in the MAAC Balancing Account pursuant to the MAAC procedure, thereafter both the recorded revenue and recorded investment-related revenue requirement shall be reflected in the MAAC Balancing Account; and

- The ultimately adopted reasonable level of investment for each project shall be reflected in rates pursuant to an application filed to establish the reasonable and prudent level of recorded costs of the completed project. Such applications shall be filed no later than six months after the final portion of each project is placed in service.

PSD and Edison propose that the revenue requirement associated with San Onofre Nuclear Generating Station Unit No. 1 Integrated Living Schedule Cycles IX, X, and XI ("SONGS 1-ILS") be reflected in base rates in this general rate case proceeding. The 1988 Test Year revenue requirement associated with SONGS 1 ILS is $21.8 million, based on Edison's proposed rate of return and capital structure.

PSD and Edison propose in this Test Year 1988 General Rate Case ("GRC") that the following MAAC rate level increases, equal to 75 percent of the annualized revenue requirement, be authorized for each of the projects noted below:

Project	Projected Initial In-Service Date	Annualized Revenue Requirement 1/ ($M)	MAAC Rate Increase (¢/kWh)	MAAC Revenue Increase ($M)
Balsam Meadow Hydroelectric Generating Project	Prior to 1/1/88	50,268	0.059	37,855
Devers-Valley-Serrano 500 kV T/L	Prior to 1/1/88	27,078	0.032	20,532
Sylmar-Pacific HVDC Intertie Expansion	December 31, 1988	20,227 2/	0.024 2/	15,399 2/
		0 3/	0 3/	0 3/
Devers-Palo Verde No. 2 Transmission Line	June 1, 1990	40,876	0.048	30,797

1/ Assumes Edison's proposed rate of return (ROCE of 13.75%) and capital structure.

2/ Edison's position regarding the appropriate revenue requirement.

3/ PSD's position regarding the appropriate revenue requirement.

The revenue requirements set forth in the above table are based upon Edison's proposed rate of return on common equity and proposed capital structure. It is proposed that the revenue requirements and resulting MAAC rate level increases be adjusted to reflect the adopted rate of return on common equity and capital structure and any other revenue requirement factors adopted by in the Commission in the 1988 GRC or Attrition filings.

C. Background

On March 2, 1987, the PSD filed a motion requesting that Edison be ordered to exclude from this 1988 GRC all costs associated with uncompleted capital projects in excess of $50 million in accordance with Public Utilities Code Section 463 ("PUC §463"). Edison filed a response in opposition to PSD's motion on March 16, 1987. The Administrative Law Judge ("ALJ") issued a ruling on May 5, 1987, wherein he denied PSD's motion to exclude certain capital projects from this 1988 GRC and directed Edison and PSD to develop for inclusion in the general rate case processing plan for this and future Edison general rate cases, a detailed procedure which would allow Edison to bill revenue when plant is placed in service; and enable the Commission to have an ample opportunity to consider the reasonableness issues without the time constraints imposed by the general rate case process.

The ALJ's Ruling proposed the following three-part procedure:

> "1. General rate case decisions would authorize utility to file Advice Letter rate increases subject to refund with interest for capital projects in excess of $50 million once they have gone into service;
>
> 2. Advice Letter increases would trigger an accounting mechanism to track the revenues collected subject to refund with interest pending a finding of reasonableness; and
>
> 3. Utilities would be required to file a separate application for a finding of reasonableness for each project for which an Advice Letter increase has been requested."

II

PROPOSED PROCEDURE

The apparent goal of the procedure contained in the ALJ's Ruling is to enable the Commission to review the reasonableness issues outside the schedule imposed by the General Rate Case Plan while allowing Edison to ultimately recover the revenue requirement associated with reasonable and prudent expenditures for new additions to Edison's plant which are estimated to cost more than $50 million. The proposed procedure contained in the ALJ's Ruling provides for the tracking of revenues but does not provide for the tracking of the associated revenue requirement. In order to determine the rate levels for the Advice Letter filing, the forecast revenue requirement would have to be litigated in a general rate case, thus litigating the construction costs of the project at least twice--once in the general rate case and again in an application to establish final rates. This could result in a significant delay in the processing of the general rate case. This difficulty can be eliminated by adopting a procedure, such as the MAAC, which tracks both recorded revenue and recorded investment-related revenue requirement. The current MAAC procedure provides an appropriate methodology to track both revenues and revenue requirement, enables the Commission to review the reasonableness of plant investment, and, if appropriate, subsequently disallow from historical rate recovery any costs found to be unreasonable since the revenue collected is subject to refund.

The procedure contained in the ALJ's ruling provides for implementation of rate level increases filed by Advice Letter coincident with the date on which a capital project is placed into service. This would result in numerous rate level increases during the year as entire projects and/or phases of projects are placed into service, such as segments of transmission lines. The number of these rate level increases can be reduced by the adoption of the MAAC procedure which tracks both revenue and investment-related revenue requirement. This would enable Edison to ultimately recover its reasonable and prudent investment-related costs while initially deferring a rate level change. This, in turn, would allow the Commission to increase MAAC rates at the same time as other rate level changes are made.

The proposed modifications to the MAAC procedure, discussed below, provide for a tracking of investment-related revenue requirement and revenues, which should remove any controversy surrounding the establishment of interim rate levels, thus avoiding litigating the amount of plant investment in a general rate case and the reasonableness review proceeding. For MAAC revenue requirement purposes which result in the interim rate level increases, an estimate of plant costs would be used, and for reasonableness review purposes, the recorded costs would be available. The MAAC Balancing Account ensures that only the ultimately adopted reasonable level of investment will be reflected in base rates. In addition, the proposed procedure reduces the number of required rate level changes which would occur during the year under the procedure contained in the ALJ's Ruling. The procedure also specifically provides for equal and opposite rate level changes between ECAC and MAAC rate levels on the in-service date of the capital addition to reflect any fuel savings. It is therefore proposed that the procedure contained in the ALJ's Ruling be modified to provide for the tracking of <u>both</u> revenues and investment-related revenue requirement by the inclusion in the MAAC procedure of those projects which are estimated to cost more than $50 million.

The proposed procedure would be administratively efficient and should minimize the issues arising in the general rate case proceeding. The proposed procedure modifies the existing MAAC procedure to include as Specified Major Additions the projects for which MAAC treatment has been adopted in a general rate case.

The proposed procedure requires that certain actions occur through the course of several existing ratemaking procedures: the General Rate Case, Advice Letter filings, Annual Attrition filings, the MAAC procedure and an application for final rate relief. The specific actions that are to occur during the course of each of these ratemaking procedures are identified and discussed in the following paragraphs.

A. <u>Items to Be Determined by a Commission Decision Rendered in a General Rate Case Proceeding</u>

The following events and/or actions are to be addressed through the normal course of the general rate case proceeding. It is intended that Edison file adequate documentation which provides sufficient support for the Commission's decision which addresses the following points:

1. Capital projects estimated to cost more than $50 million, which can reasonably be expected to be placed in service prior to, or during, the period commencing with the general rate case test year through the subsequent attrition test years and which are to be reflected in rates for the first time, are to be identified in the general rate case with sufficient specificity to be included as Specified Major Additions in the MAAC;

2. For each capital project where major portions of the project are placed in service prior to the total project being complete, each major subproject shall be identified. Examples of major subprojects would be a segment of a transmission line or a substation component part of a total transmission line project;

3. The plant in-service criteria for each project or subproject are to be determined;

4. The plant in-service date for each project or subproject is forecast;

5. The plant in-service amounts for each project or subproject are estimated. (The initial plant in-service amounts are to be based on

the costs estimated by the utility except that such costs shall not exceed any previously determined cost cap established by the Commission. In the event that a cost cap has not been previously established by the Commission, the Commission shall determine such a level of costs for the purposes of establishing a reasonable level of MAAC rates in the general rate case decision.);

6. The depreciated rate base for an annualized period commencing on the forecast in-service date for each project or subproject is estimated;

7. The annualized investment-related revenue requirement associated with each project or subproject is estimated for the 12-month period commencing on the forecast in-service date for each project or subproject; and

8. The MAAC rate level to be filed by Advice Letter filing on the project's actual in-service date is to be determined.

B. <u>Rate and Tariff Changes to Be Implemented Through Advice Letter Filings</u>

The following rate actions are to be implemented through the Advice Letter filing procedure as contemplated by General Order No. 96A and are to be made effective on date of filing.

1. An Advice Letter filing shall be made on the actual in-service date of each project or subproject implementing the Commission's general rate case decision which authorized the inclusion of the project or subproject as a Specified Major Addition under the MAAC; thus permitting the recording of investment-related revenue requirement in a separate MAAC Balancing Account for each project. This Advice Letter filing shall also contain: (1) an affidavit stating that the plant in-service criteria, as set forth in the Commission's decision rendered in the general rate case proceeding, have been met for each project or subproject; and (2) identify all anticipated significant post-COD project completion investment which are also applicable for inclusion in the MAAC.

2. An Advice Letter may be filed which requests implementation of the MAAC rate level change authorized in the Commission's decision rendered in the general rate case proceeding at an appropriate time so as to coincide with other rate changes. At the present time, it is anticipated that Advice Letters will be filed requesting MAAC rate increases equal to the reduction in ECAC rates, if any, due to fuel savings, associated with the project be filed and made effective on the plant in-service date. Should additional MAAC rate increases be required to reflect the full MAAC rate increase authorized by the Commission in its general rate case decision, they are to be filed by Advice Letter to be made effective June 1 of each year to coincide with ECAC revision dates or on January 1 of each year to be coincident with base rate changes. However, for major projects where the rate increase is in excess of $50 million, Edison may file an Advice Letter implementing a rate increase on the in-service date of the project or subproject.

C. Items to Be Determined by a Commission Decision in the Annual Attrition Proceeding

Through the course of the annual attrition proceeding, the MAAC rates may be modified to reflect rate of return changes or any other changes that are applicable as a result of the attrition filing.

D. Application for Final Rates

Edison shall file within six months of a completed project's final in-service date an application which requests that the Commission establish the adopted level of reasonable investment costs incurred through the date on which the application is filed; establish the reasonableness of the recorde revenue and revenue requirement reflected in the MAAC Balancing Account for such project; set forth the specific time and procedure to transfer recovery of the investment-related revenue requirement from MAAC recovery to base rate recovery; establish an adopted annualized base rate revenue requirement; establish rates which will amortize any balance in the MAAC Balancing Account related to such project over an appropriate period; and establish base rate levels and the authorized level of base rate revenue under the ERAM.

E. Procedural Relationships to Rate Case Processing Plan and Attrition Procedure

The above-noted actions are anticipated to occur within the existing rate case processing plan and Advice Letter filing procedures.

F. Tariff Changes Required to Implement the Proposed Procedure

In order to implement the above-described procedure, it is proposed that the following modifications to the MAAC tariff contained in Part K of the Preliminary Statement are necessary to reflect implementation of this ratemaking procedure.

1. Proposed Modifications to the MAAC Tariff

It is proposed that the MAAC tariffs be modified to reflect the establishment of a separate Annual Major Additions Rate, a separate Major Additions Adjustment Account ("MAAC Balancing Account") and a separate Balancing Rate for each Specified Major Addition for the purpose of separately tracking the recorded costs and revenues associated with each project.

The proposed modifications to the MAAC tariff are set forth below:

a. PSD and Edison propose to add the following terms to Section 3, Definitions, in order to properly identify the investment types applicable for inclusion in the MAAC and to define the termination date for projects no longer includable in the MAAC:

"f. Pre-COD Investment:

The Pre-COD Investment shall be the investment in a portion of the Company's Electric Plant in Service made prior to the Commercial Operating Date.

"g. Post-COD Investment:

The Post-COD Investment shall be the investment in a portion of the Company's Electric Plant in Service made on or after the Commercial Operating Date.

"j. Termination Date:

The Termination Date shall be the date on which the costs incurred thereafter for a Specified Major Addition shall no longer be applicable for inclusion in the MAAC."

b. Consistent with the proposed changes to Section K.3 above, Section K.4 should be changed to reflect the investment types applicable for inclusion in the MAAC and to modify the table in Section K.3.g of the currently effective tariff to include a Termination Date for incurrence of costs for each Specified Major Addition in order to clearly terminate a project's inclusion in the MAAC procedure. The Average Ownership Rates and Average Noninvestment-Related Rates have been moved to other sections of the tariff. Section K.3.g has been renumbered to K.3.i. The proposed Section K.3.i is as follows:

"i. Specified Major Addition:

A Specified Major Addition is an addition to the Company's Electric Plant in Service between general rate proceedings which has been authorized for inclusion in the MAAC by the Commission. For purposes of calculating revisions to the MAAC rates and the entries to the Major Additions Adjustment Account, those Pre-COD Investment and Post-COD Investment-related costs applicable for inclusion in the MAAC associated with the following Specified Major Additions shall be included:

Specified Major Addition	Authorization Date	Termination Date "

c. Section K.4 should be modified to also reflect the investment types applicable for inclusion in the MAAC consistent with the proposed changes to Section K.3. The proposed Section K.4 is, in relevant part, as follows:

"4. Calculation of the Average Ownership Rate. Individual rates to reflect those Pre-COD Investment and Post-COD Investment-related costs of owning each Specified Major Addition shall be calculated as authorized by the Commission. The Average Ownership Rate for each Specified Major Addition shall be determined from the following calculations:"

d. Section K.4.e should be changed as set forth below to reflect the most recently adopted Commission jurisdictional allocation factor.

> "e. The sum of 'a' through 'd' shall be multiplied by the most recently adopted retail jurisdictional allocation factor."

e. Edison proposes to modify Section K.4.f to replace the reference to "Section 3.g" with the phrase "As set forth below", and to add a table which sets forth the Average Ownership Rate for each Specified Major Addition which was deleted from Section K.3.g. Thus, the last sentence in Section K.4.f is proposed to read as follows:

> "The result shall be the Average Ownership Rate, expressed in cents per kilowatthour, as set forth below.

Specified Major Addition	Average Ownership Rate (¢/kWh) "

f. Edison proposes to modify Section K.5 to reflect the calculation of a Balancing Rate for each Specified Major Addition and to reflect the inclusion of a table which sets forth the Balancing Rate for each Specified Major Addition. This change is required in order to specifically quantify the MAAC revenues for each Specified Major Addition. The proposed Section K.5 is as follows:

> "5. Calculation of the Balancing Rate for Each Specified Major Addition. The Balancing Rate for each Specified Major Addition shall be calculated by dividing the estimated balance in the Major Additions Adjustment Account, plus the interest forecast to accrue during the amortization period, on the Revision Date (calculated in accordance with the procedure set forth in Paragraph 7), increased to provide for Franchise Fees and Uncollectible Accounts, by the sales subject to the MAAC estimated to be sold during the amortization period. The result shall be the Balancing Rate, expressed in cents per kilowatthour. The Balancing Rate associated with each Specified Major Addition authorized for inclusion in the MAAC is set forth below:

Specified Major Addition	Balancing Rate ($/kWh) "

g. Edison proposes to modify Section K.6 such that the MAABF is the sum of the Average Ownership Rates and Balancing Rates associated with all Specified Major Additions authorized for inclusion in the MAAC. This change is required to calculate the MAABF based upon the changes previously made in Section K. Edison also proposes to update the table contained in Section K.6 to reflect the MAABF proposed herein. The proposed Section K.6 is as follows:

"6. Major Additions Adjustment Billing Factor (MAABF). The MAABF shall be the sum of the Average Ownership Rates and the Balancing Rates for each Specified Major Addition. Such MAABF, expressed in cents per kilowatthour, shall be applied on a uniform cents-per-kilowatthour basis to all sales subject to the MAAC. The application of the MAABF to sales shall be as set forth on the applicable rate schedule.

The MAABF listed below have been, or are, in effect for the periods indicated:

Effective Date	Major Additions Adjustment Billing Factor (¢/kWh)
10/09/83	0.311
01/01/84	0.492
04/01/84	0.767
01/01/85	1.270"

h. Edison proposes to modify Sections K.7 and K.7.f to reflect separate Balancing Accounts for each Specified Major Addition and changed language concerning the jurisdictional allocation factor, such that Sections K.7, K.7.e, and K.7.f read as follows:

"7. Major Additions Adjustment Account for Each Specified Major Addition. The Company shall maintain a Major Additions Adjustment Account (Balancing Account) for each Specified Major Addition. Entries to be made to this account at the end of each month will be determined from the following calculations:

e. Less: The sum of 'a' through 'd' multiplied by the most recently adopted resale jurisdictional allocation factor.

f. Less: The amount of revenue attributable to each Specified Major Addition. This amount of revenue shall be calculated by multiplying the sum of the Average Ownership Rate and Balancing Rate for each Specified Major Addition times the kilowatthours sold during the month applicable to the MAABF, reduced to provide for Franchise Fees and Uncollectible Accounts."

i. Edison proposes to modify Section K.8.f to include a table which sets forth the Average Noninvestment-Related Expense Rates deleted from Section K.3.g, and reflects the most recently adopted retail jurisdictional allocation factor. The proposed Sections K.8.e and K.8.f are as follows:

"e. The sum of 'a' through 'd' shall be multiplied by the most recently adopted retail jurisdictional allocation factor.

f. The amount in 'e' above, increased to provide for Franchise Fees and Uncollectible Accounts, shall be divided by the sales subject to the MAAC estimated to be sold during the Forecast Period. The result shall be the Average Noninvestment-Related Expense Rate, expressed in cents per kilowatthour, as set forth below.

Specified Major Addition	Average Noninvestment-Related Expense Rate (¢/kWh) "

2. Proposed MAAC Tariff Sheets

The MAAC Tariff Sheets reflecting the proposed procedure and those projects identified in Part III below are contained in Attachment 2.

III

RATE RELIEF DETERMINED IN ACCORDANCE WITH THE PROPOSED PROCEDURE

A. Applicable Projects

1. Capital Projects to Be Included in This Procedure

The following projects are expected to be placed in service prior to the start of the 1988 GRC Test Year, or during the 1988 GRC Test Year, or during the ensuing years 1989 and 1990 Attrition, and will be reflected in rates for the first time on or after January 1, 1988, and are therefore applicable for inclusion in the MAAC as Specified Major Additions: the Balsam Meadow Hydroelectric Generating Plant, the Devers-Valley-Serrano 500 kV Transmission Line, Sylmar-Pacific HVDC Intertie Expansion 2/ and the Devers-Palo Verde No. 2 Transmission Line. 3/

2/ The PSD believes that this project should not be reflected in rates, however, if the Commission grants rate recovery for the project, it should be included in this procedure.

3/ This project is to be included in this procedure only if the Commission grants a Certificate of Public Convenience and Necessity for the project.

2. <u>San Onofre Nuclear Generating Station Unit 1 Integrated Living Schedule (SONGS 1 ILS) Plant Additions Should Not Be Included in This Procedure.</u>

The SONGS 1 ILS plant additions which Edison is seeking authority to include in base rate in this GRC Application are the same SONGS 1 ILS plant modifications that the Commission has already authorized (in OII 83-10-02) Edison to implement for Fuel Cycles IX, X, and XI. In Decision No. 85-12-024, the Commission authorized Edison to spend an amount of up to $201 million (in January 1, 1986 dollars) for SONGS 1 ILS modifications through Fuel Cycles IX, X, and XI. In Application No. 85-05-008, filed May 1, 1985, Edison requested, among other things, base rates to reflect the SONGS 1 ILS plant additions for Fuel Cycle IX.

The modifications being implemented under the ILS program comprise numerous distinct and individual projects. The individual SONGS 1 ILS plant additions for Fuel Cycles IX, X, and XI are each less than $50 million, and therefore PUC §463 is not applicable to them.

Therefore, they should be reflected in base rates through the normal general rate case procedure in the same manner as any other plant addition which costs less than $50 million.

B. <u>Requested Rate Relief for Includable Projects</u>

1. <u>Summary</u>

PSD and Edison propose that the following projects be authorized for inclusion in the MAAC as Specified Major Additions, and that the following MAAC rate level increases, equal to 75 percent of the annualized revenue requirement, be authorized for each of the projects noted below:

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Project	Projected Initial In-Service Date	Annualized Revenue Requirement 1/ ($M)	MAAC Rate Increase (¢/kWh)	MAAC Revenue Increase ($M)
Balsam Meadow Hydroelectric Generation Project	Prior to 1/1/88	50,268	0.059	37,855
Devers-Valley-Serrano 500 kV T/L	Prior to 1/1/88	27,078	0.032	20,532
Sylmar-Pacific HVDC Intertie Expansion	December 31, 1988	20,227 2/	0.024 2/	15,399 2/
		0 3/	0 3/	0 3/
Devers-Palo Verde Transmission Line No. 2	June 1, 1990	40,876	0.048	30,797

1/ Assumes Edison's proposed rate of return (ROCE of 13.75%) and capital structure.

2/ Edison's position regarding the appropriate level of plant investment and resultant revenue requirement.

3/ PSD's position regarding the appropriate level of plant investment and resultant revenue requirement.

The revenue requirements set forth in the above table are based upon Edison's proposed rate of return on common equity and proposed capital structure. It is proposed that the revenue requirements and resulting MAAC rate level increases be adjusted to reflect the adopted rate of return on common equity, capital structure and any other revenue requirement factors determined by the Commission.

2. Balsam Meadow Hydroelectric Generation Project

a. Description of Project

The Balsam Meadow Hydroelectric Generation Project is a 200 MW hydroelectric generating station, located between Huntington and Shaver Lakes, approximately 45 miles northeast of Fresno. It consists of an underground hydroelectric powerhouse, forebay and dam, waterways and related facilities, and approximately 4.5 miles of 220 kV transmission line.

b. In-Service Criteria

The Balsam Meadow Hydroelectric Generation Project shall be considered commercially operable when the following operational criteria have been met:

(1) When Edison's Engineering and Construction Department has completed the guaranteed performance tests as defined in purchase contracts with the turbine and generator manufacturers; and

(2) When Edison's Engineering and Construction Department has completed other required operational testing in conformance with sound engineering practices and applicable industry standards; and

(3) When the generating unit is synchronized with the Edison electric system grid and completion items are identified; and

(4) When operation and maintenance of the facility has been turned over by Edison's Engineering and Construction Department to its Power Supply Department.

c. Plant In-Service Date

Commercial operation of the project is estimated to be December 1, 1987.

d. Annualized Revenue Requirement

Table III-A sets forth the estimated annualized revenue requirement associated with the Balsam Meadow Hydroelectric Generation Project based upon the plant in-service date of December 1, 1987. Since the project is expected to be placed in service prior January 1, 1988, the revenue requirement is set forth for the entire Test Year 1988. The 1988 revenue requirement set forth herein is based on the same revenue requirement factors, such as rate of return (ROCE of 13.75%) and the net-to- gross multiplier, and CPUC jurisdictional allocation factor used by the Company in Exhibit No. (SCE-6)_____, "Results of Operations". Edison's estimates that the 1988 revenue requirement for the Balsam Meadow Hydroelectric Facility is $50.3 million on a CPUC jurisdictional basis.

e. Proposed Increase in the Major Additions Adjustment Billing Factor ("MAABF")

The Balsam Meadow Hydroelectric Facility is to become a Specified Major Addition in the MAAC effective January 1, 1988. The proposed increase in the Average Ownership Rate ("AOR") results in an increase in the MAABF of 0.059¢/kWh is proposed to be effective for service rendered on and after January 1, 1988. The increase in the MAABF results in an annualized increase in revenue of $37.8 million, which represents about 75 percent of the estimated revenue requirement. The calculation of the increase to the MAABF is set forth in Table III-B.

3. Devers-Valley-Serrano 500 kV Transmission Line

a. Description of Project

The Devers-Valley-Serrano Transmission Line is an approximately 80-mile, 500 kV line between Edison's Devers Substation near Palm Springs, via Valley Substation near Romoland to Serrano Substation in the City of Orange.

b. In-Service Criteria

This transmission line, or significant line segment or component of this transmission line, shall be considered commercially operable when the following operational criteria have been met:

(1) When a transmission line, or significant line segment or component of a transmission line, is electrically energized and integrated with the Edison electric system grid and completion items have been identified; and

(2) When Edison has completed required equipment testing in conformance with sound engineering practices and applicable industry standards; and

(3) When operation and maintenance of the transmission line, or significant line segment or component has been turned over to Edison's Power Supply Department.

c. Plant In-Service Date

The estimated final plant in-service date for this project is July 6, 1987.

d. Annualized Revenue Requirement

Table III-C sets forth the calculated annualized revenue requirement associated with the Devers-Valley-Serrano 500 kV transmission line facility based upon the final plant in-service date of July 6, 1987. Since the project is expected to be placed in service prior to January 1, 1988, the revenue requirement is set forth for the entire Test Year 1988. The 1988 revenue requirement set forth herein is based on the same revenue requirement factors, such as rate of return (ROCE of 13.75%) and the net-to-gross multiplier, and CPUC jurisdictional allocation factor used by the Company in Exhibit No. (SCE-6)______, "Results of Operations". Edison's estimates for the 1988 revenue requirement for the Devers-Valley-Serrano 500 kV transmission line facility is $27.1 million on a CPUC jurisdictional basis.

e. Proposed Increase in the MAABF

The Devers-Valley-Serrano 500 kV transmission line facility is to become a Specified Major Addition in the MAAC effective January 1, 1988. The proposed increase in the Average Ownership Rate ("AOR") results in an increase in the MAABF of 0.032¢/kWh, and is proposed to be effective for service rendered on and after January 1, 1988. The increase in the MAABF results in an annualized increase in revenue of $20.5 million, which represents about 75 percent of the estimated revenue requirement. The calculation of the increase to the MAABF is set forth in Table III-D.

4. Sylmar-Pacific HVDC Intertie Expansion

a. Description of Project

The Sylmar-Pacific HVDC Intertie Expansion (also known as the DC Terminal Expansion), is a project to increase the transmission capacity of the Pacific Northwest/Southwest Direct Current Intertie by approximately 1100 MW. Construction of the project involves the addition of new AC/DC converter equipment and related facilities at both terminals of the line (Celilo near the Dalles, Oregon, and Sylmar, in Los Angeles).

As part of the project, a Static Var Control Device consisting of shunt capacitors and thyristors, will be installed at PGandE's Malin Substation. The device will provide continuous and transient voltage support in the PGandE area in the event of a bipole outage.

b. In-Service Criteria

This transmission line, or significant line segment or component of a transmission line, shall be considered commercially operable when the following operational criteria have been met:

(1) When a transmission line, or significant line segment or component of a transmission line is electrically energized and integrated with the Edison electric system grid and completion items have been identified; and

(2) When Edison has completed required equipment testing in conformance with sound engineering practices and applicable industry standards; and

(3) When operation and maintenance of the transmission line, or significant line segment or component has been released for operation by the project manager at Los Angeles Department of Water and Power.

c. Plant In-Service Date

The estimated in-service date is December 31, 1988.

d. Annualized Revenue Requirement

Edison and PSD disagree as to the need for and the cost-effectiveness of the Sylmar-Pacific HVDC Intertie Expansion (also known as the DC Terminal Expansion Project). PSD believes that the project should not go forward, however, if the Commission permits the project to go forward and be reflected in rates, PSD proposes that a cost cap not to exceed $47 million should be established for the project, whereas Edison believes that its entire forecast cost of $104,627 thousand should be reflected in base rates.

Table III-E sets forth Edison's proposed annualized revenue requirement associated with the Sylmar-Pacific HVDC Intertie Expansion facility based upon the plant in-service date of December 31, 1988. The annualized revenue requirement set forth herein is based on the same revenue requirement factors, such as rate of return (ROCE of 13.75%), the net-to-gross multiplier, and CPUC jurisdictional allocation factor used by the Company in Exhibit No. (SCE-6)______, "Results of Operations". Edison estimates that the annualized revenue requirement for the Sylmar-Pacific HVDC Intertie Expansion facility is $20.2 million on a CPUC jurisdictional basis.

Table III-G sets forth the annualized revenue requirement associated with the Sylmar-Pacific HVDC Intertie Expansion facility based upon the plant in-service date of December 31, 1988, assuming that the project is permitted to be reflected in rates and that the maximum cost cap amount is $47 million, as proposed by PSD. The annualized revenue requirement set forth herein is based on the same revenue requirement factors, such as rate of return, the net-to-gross multiplier, and CPUC jurisdictional allocation factor used by the Company in Exhibit No. (SCE-6)______, "Results of Operations". PSD estimates that the annualized revenue requirement, assuming an adopted cost cap of $47 million, is $9.3 million on a CPUC jurisdictional basis.

e. Proposed Increase in the MAABF

Edison proposes that the Sylmar-Pacific HVDC Intertie Expansion facility is to become a Specified Major Addition in the MAAC effective on its in-service date currently expected to be December 1, 1988. The Edison-proposed increase in the AOR results in an increase in the MAABF of 0.024¢/kWh, and is proposed to be effective for service rendered on and after its in-service date. The increase in the MAABF results in an annualized increase in revenue of $15.4 million, which represents about 75 percent of the annualized revenue requirement. The calculation of the increase to the MAABF is set forth in Table III-F.

The increase, based upon PSD's alternative proposal (assuming the maximum cost cap of $47 million), results in an increase in the MAABF of 0.011¢/kWh, and is proposed to be effective for the service rendered on and after its in-service date. The increase in the MAABF results in an annualized increase in revenue of $7.1 million, which represents about 75 percent of the annualized revenue requirement, based on an investment cost cap of $47 million. The calculation of the increase to the MAABF is set forth in Table III-H.

5. Devers-Palo Verde No. 2 Transmission Line

a. Description of Project

The proposed Devers-Palo Verde #2 Transmission Line is an approximately 238-mile, 500 kV line between the Palo Verde High Voltage Switchyard near Phoenix, Arizona and Edison's Devers Substation near Palm Springs. Some modifications to the 220 kV system west of Devers will also be required.

b. In-Service Criteria

This transmission line, or significant line segment or component of this transmission line, shall be considered commercially operable when the following operational criteria have been met:

(1) When a transmission line, or significant line segment or component of a transmission line, is electrically energized and integrated with the Edison electric system grid and completion items have been identified; and

(2) When Edison has completed required equipment testing in conformance with sound engineering practices and applicable industry standards; and

(3) When operation and maintenance of the transmission line, or significant line segment or component has been turned over to Edison's Power Supply Department.

c. Plant In-Service Date

The estimated plant in-service date for this project is June 1, 1990.

d. Annualized Revenue Requirement

The Devers-Palo Verde #2 Transmission Line is currently being reviewed by the Commission in Application No. 85-12-012, wherein Edison has requested a Certificate of Public Convenience and Necessity ("CPCN") for the project. Assuming that the Commission grants a CPCN for the project, it is anticipated that a cost cap will be established. It is intended that the increase in the MAABF be based upon 75 percent of the revenue requirement and that the revenue requirement be based on Edison's share of the cost cap level or an estimated cost of $246 million, whichever is less.

Table III-I sets forth the calculated annualized revenue requirement associated with the proposed Devers-Palo Verde #2 Transmission Line facility based upon the plant in-service date of June 1, 1990. The revenue requirement set forth herein is based on the same revenue requirement factors, such as rate of return, the net-to-gross multiplier, and CPUC jurisdictional allocation factor used by the Company in Exhibit No. (SCE-6)______, "Results of Operations". The estimated revenue requirement for the proposed Devers-Palo Verde #2 kV transmission line facility is $40.8 million on a CPUC jurisdictional basis based on an estimated cost of $246 million.

e. Proposed Increase in the MAABF

The proposed Devers-Palo Verde 2 Transmission Line facility is to become a Specified Major Addition in the MAAC effective on the project's in-service date. The increase in the Average Ownership Rate ("AOR") results in an increase in the MAABF of 0.048¢/kWh, and is proposed to be effective for service rendered after the in-service date of the project. The increase in the MAABF results in an annualized increase in revenue of $30.8 million, which represents about 75 percent of the estimated revenue requirement. The calculation of the increase to the MAABF is set forth in Table III-J.

APPENDIX A

ATTACHMENT 1

SUMMARY OF EARNINGS AND RATE CHANGE TABLES

APPENDIX A
TABLE III-A

1988 SUMMARY OF EARNINGS FOR THE BALSAM MEADOW HYDROELECTRIC FACILITY

(Thousands of Dollars)

Line No.	Description	Total System (1)	CPUC Jurisdiction 1/ (2)
1.	TOTAL REVENUE REQUIREMENT	51,927	50,268
2.	EXPENSES		
3.	Depreciation Expense	4,976	4,817
4.	Ad Valorem Taxes	2,242	2,170
5.	Income Taxes	12,008	11,624
6.	Franchise Fees	379	367
7.	Uncollectibles	128	124
8.	TOTAL EXPENSES	19,733	19,102
9.	NET REVENUE	32,194	31,166
10.	RATE BASE	284,655	275,560
11.	RATE OF RETURN (%)	11.31	11.31

1/ Based on a CPUC Jurisdictional Allocation Factor of: 0.96805

APPENDIX A

TABLE III-B

CALCULATION OF THE AVERAGE OWNERSHIP RATE AND RESULTANT MAABF RATE INCREASE FOR THE BALSAM MEADOW HYDROELECTRIC FACILITY

Line No.	Description	($M) (1)	Forecast Sales (GWh) (2)	Average Ownership Rate Increase (¢/kWh) (3)
1.	Forecast 1988 Revenue Requirement	51,927		
2. 3.	Forecast 1988 CPUC Jurisdictional Revenue Requirement @ .96805 1/	50,268		
4.	Forecast 1988 Sales 1/ 2/		64,161.4	
5.	Forecast Average Ownership Rate Increase			0.059 3/

1/ The CPUC jurisdictional factor of .96805 and the forecast 1988 sales are as set forth in Edison's Test Year 1988 General Rate Case.

2/ Includes DE Adjustment of 27.9 kWh.

3/ $\frac{50{,}268\text{ M}}{64{,}161.4\text{ GWh}}$ .75 = 0.059¢/kWh

APPENDIX A
TABLE III-C

1988 SUMMARY OF EARNINGS
FOR THE DEVERS-VALLEY-SERRANO 500 KV TRANSMISSION LINE

(Thousands of Dollars)

Line No.	Description	Total System (1)	CPUC Jurisdiction 1/ (2)
1.	TOTAL REVENUE REQUIREMENT	27,972	27,078
2.	EXPENSES		
3.	Depreciation Expense	5,776	5,591
4.	Ad Valorem Taxes	1,113	1,077
5.	Income Taxes	6,354	6,151
6.	Franchise Fees	204	197
7.	Uncollectibles	69	67
8.	TOTAL EXPENSES	13,516	13,083
9.	NET REVENUE	14,456	13,995
10.	RATE BASE	127,819	123,735
11.	RATE OF RETURN (%)	11.31	11.31

1/ Based on a CPUC Jurisdictional Allocation Factor of: 0.96805

APPENDIX A

TABLE III-D

CALCULATION OF THE AVERAGE OWNERSHIP RATE AND RESULTANT MAABF RATE INCREASE FOR THE DEVERS-VALLEY-SERRANO 500 KV TRANSMISSION LINE

Line No.	Description	($M) (1)	Forecast Sales (GWh) (2)	Average Ownership Rate Increase (¢/kWh) (3)
1.	Forecast 1988 Revenue Requirement	27,972		
2.	Forecast 1988 CPUC Jurisdictional			
3.	Revenue Requirement @ .96805 1/	27,078		
4.	Forecast 1988 Sales 1/ 2/		64,161.4	
5.	Forecast Average Ownership Rate Increase			0.032 3/

1/ The CPUC jurisdictional factor of .96805 and the forecast 1988 sales are as set forth in Edison's Test Year 1988 General Rate Case.

2/ Includes DE Adjustment of 27.9 kWh.

3/ $\frac{27{,}078\text{ M}}{64{,}161.4\text{ GWh}}\ .75 = 0.032$¢/kWh

APPENDIX A
TABLE III-E

SOUTHERN CALIFORNIA EDISON COMPANY'S
PROPOSED 1988 ANNUALIZED SUMMARY OF EARNINGS
FOR THE SYLMAR-PACIFIC HVDC INTERTIE EXPANSION

(Thousands of Dollars)

Line No.	Description	Total System (1)	CPUC Jurisdiction 1/ (2)
1.	TOTAL REVENUE REQUIREMENT	20,895	20,227
2.	EXPENSES		
3.	Depreciation Expense	4,242	4,106
4.	Ad Valorem Taxes	836	809
5.	Income Taxes	4,314	4,176
6.	Franchise Fees	153	148
7.	Uncollectibles	52	50
8.	TOTAL EXPENSES	9,597	9,289
9.	NET REVENUE	11,298	10,938
10.	RATE BASE	99,899	96,707
11.	RATE OF RETURN (%)	11.31	11.31

1/ Based on a CPUC Jurisdictional Allocation Factor of: 0.96805

APPENDIX A
TABLE III-F

SOUTHERN CALIFORNIA EDISON COMPANY'S
PROPOSED CALCULATION OF THE AVERAGE OWNERSHIP RATE
AND RESULTANT MAABF RATE INCREASE FOR THE
SYLMAR-PACIFIC HVDC INTERTIE EXPANSION

Line No.	Description	($M) (1)	Forecast Sales (GWh) (2)	Average Ownership Rate Increase (¢/kWh) (3)
1.	Forecast 1988 Revenue Requirement	20,895		
2. 3.	Forecast 1988 CPUC Jurisdictional Revenue Requirement @ .96805 1/	20,227		
4.	Forecast 1988 Sales 1/ 2/		64,161.4	
5.	Forecast Average Ownership Rate Increase			0.024 3/

1/ The CPUC jurisdictional factor of .96805 and the forecast 1988 sales are as set forth in Edison's Test Year 1988 General Rate Case.
2/ Includes DE Adjustment of 27.9 kWh.
3/ $\frac{20{,}227\text{ M}}{64{,}161.4\text{ GWh}}$ .75 = 0.024¢/kWh

APPENDIX A
TABLE III-G

PUBLIC STAFF DIVISION'S
ALTERNATE PROPOSAL
FOR THE SYLMAR-PACIFIC HVDC INTERTIE EXPANSION
ANNUALIZED 1988 SUMMARY OF EARNINGS

(Thousands of Dollars)

Line No.	Description	Total System (1)	CPUC Jurisdiction 1/ (2)
1.	TOTAL REVENUE REQUIREMENT	9,576	9,270
2.	EXPENSES		
3.	Depreciation Expense	1,944	1,882
4.	Ad Valorem Taxes	383	370
5.	Income Taxes	1,977	1,914
6.	Franchise Fees	70	68
7.	Uncollectibles	24	23
8.	TOTAL EXPENSES	4,398	4,257
9.	NET REVENUE	5,178	5,013
10.	RATE BASE	45,784	44,321
11.	RATE OF RETURN (%)	11.31	11.31

1/ Based on a CPUC Jurisdictional Allocation Factor of: 0.96805

APPENDIX A

TABLE III-H

PUBLIC STAFF DIVISION'S
CALCULATION OF THE AVERAGE OWNERSHIP RATE
AND RESULTANT MAABF RATE INCREASE FOR THE
SYLMAR-PACIFIC HVDC INTERTIE EXPANSION

Line No.	Description	($M) (1)	Forecast Sales (GWh) (2)	Average Ownership Rate Increase (¢/kWh) (3)
1.	Forecast 1988 Revenue Requirement	9,576		
2. 3.	Forecast 1988 CPUC Jurisdictional Revenue Requirement @ .96805 1/	9,270		
4.	Forecast 1988 Sales 1/ 2/		64,161.4	
5.	Forecast Average Ownership Rate Increase			0.011 3/

1/ The CPUC jurisdictional factor of .96805 and the forecast 1988 sales are as set forth in Edison's Test Year 1988 General Rate Case.
2/ Includes DE Adjustment of 27.9 kWh.
3/ $\frac{9,270\text{ M}}{64,161.4\text{ GWh}}$ .75 = 0.011¢/kWh

APPENDIX A
TABLE III-I

SUMMARY OF EARNINGS
FOR THE PROPOSED DEVERS-PALO VERDE 2 TRANSMISSION LINE
BASED ON 1988 REVENUE REQUIREMENT FACTORS

(Thousands of Dollars)

Line No.	Description	Total System (1)	CPUC Jurisdiction 1/ (2)
1.	TOTAL REVENUE REQUIREMENT	42,225	40,876
2.	EXPENSES		
3.	Depreciation Expense	6,326	6,124
4.	Ad Valorem Taxes	2,382	2,306
5.	Income Taxes	9,585	9,279
6.	Franchise Fees	308	298
7.	Uncollectibles	104	101
8.	TOTAL EXPENSES	18,706	18,108
9.	NET REVENUE	23,519	22,768
10.	RATE BASE	207,952	201,308
11.	RATE OF RETURN (%)	11.31	11.31

1/ Based on a CPUC Jurisdictional Allocation Factor of: .96805

APPENDIX A
TABLE III-J

CALCULATION OF THE AVERAGE OWNERSHIP RATE AND RESULTANT MAABF RATE INCREASE FOR THE PROPOSED DEVERS-PALO VERDE 2 TRANSMISSION LINE

Line No.	Description	($M) (1)	Forecast Sales (GWh) (2)	Average Ownership Rate Increase (¢/kWh) (3)
1.	Forecast 1990 Revenue Requirement	42,225		
2. 3.	Forecast 1990 CPUC Jurisdictional Revenue Requirement @ .96805 1/	40,876		
4.	Forecast 1988 Sales 1/ 2/		64,161.4	
5. 6.	Forecast Average Ownership Rate Increase			0.048 3/

1/ The CPUC jurisdictional factor of .96805 and the forecast 1988 sales are as set forth in Edison's Test Year 1988 General Rate Case.

2/ Includes DE Adjustment of 27.9 kWh.

3/ $\frac{40,876 \text{ M}}{64,161.4 \text{ GWh}}$ .75 = 0.048¢/kWh

APPENDIX A

ATTACHMENT 2

MAAC TARIFF

PRELIMINARY STATEMENT

(Continued)

K. MAJOR ADDITIONS ADJUSTMENT CLAUSE (MAAC)

1. Purpose. The purpose of the Major Additions Adjustment Clause (MAAC) is to reflect in rates, through application of the Major Additions Adjustment Billing Factor (MAABF) and the Annual Major Additions Rate (AMAR), certain costs of owning, operating, and maintaining (excluding all costs recovered through the Company's Energy Cost Adjustment Clause or through the currently effective base rates) specified major plant additions (Specified Major Additions) authorized for inclusion in the MAAC by the California Public Utilities Commission (Commission). The currently authorized Specified Major Additions are set forth in Section 3.g. The costs applicable for inclusion in the MAAC for each Specified Major Addition will be recovered through the MAAC until base rates become effective which include all such costs. At such time as the MAAC provision is terminated, any accumulated differential in the Major Additions Adjustment Account, as described and limited in Section 7, shall be transferred to the Energy Cost Adjustment Account or such other appropriate balancing account.

2. Applicability. The MAAC provision applies to certain rate schedules and certain special contracts subject to the jurisdiction of the Commission.

3. Definitions.

a. Authorization Date:

The Authorization Date shall be the date on which the Commission authorizes the inclusion of a Specified Major Addition in the MAAC.

b. Effective Date:

The Effective Date for the revised MAAC rates shall be the Revision Date or such other date as the Commission may authorize. The revised MAAC rates shall be applied to sales for service rendered on and after the Effective Date and shall continue thereafter until the next such MAAC rates become effective or until the MAAC is terminated.

c. Forecast Period:

The Forecast Period for calculating the MAABF and the AMAR shall be the twelve-calendar-month period commencing with the Revision Date.

d. Franchise Fees and Uncollectible Accounts:

Franchise Fees and Uncollectible Accounts shall be the rate derived from the Company's most recent general rate decision to provide for franchise fees and uncollectible accounts expense.

e. Interest Rate:

The Interest Rate shall be 1/12 of the most recent month's interest rate on Commercial Paper (prime, three months) published in the Federal Reserve Statistical Release, C.13. Should publication of the interest rate on Commercial Paper (prime, three months) be discontinued, interest will so accrue at the rate of 1/12 of the most recent month's interest rate on Commercial Paper, which most closely approximates the rate that was discontinued and which is published in the Federal Reserve Statistical Release, C.13, or its successor publication.

NEW f. Pre-COD Investment:

The Pre-COD Investment shall be the investment in a portion of the Company's Electric Plant In-Service made prior to the Commercial Operating Date.

NEW g. Post-COD Investment:

The Post-COD Investment shall be the investment in a portion of the Company's Electric Plant In-Service made on or after the Commercial Operating Date.

(Continued)

(To be inserted by utility)	Issued by	(To be inserted by Cal. P.U.C.)
Advice Letter No. -E	Michael R. Peevey	Date Filed
	Name	
Decision No.	Executive Vice President	Effective
870522C01 (1)	Title	Resolution No.

PRELIMINARY STATEMENT

(Continued)

K. MAJOR ADDITIONS ADJUSTMENT CLAUSE (MAAC) (Continued)

3. Definitions. (Continued)

h. Revision Date:

The Revision Date for calculating the MAABF and the AMAR shall be January 1 of each year. Applications for MAAC rate revisions calculated in accordance with the provisions described herein shall be filed with the Commission at least 90 days prior to the Revision Date.

i. Specified Major Addition:

CHANGE

A Specified Major Addition is an addition to the Company's Electric Plant In-Service between general rate proceedings which has been authorized for inclusion in the MAAC by the Commission. For purposes of calculating revisions to the MAAC rates and the entries to the Major Additions Adjustment Account, those Pre-COD Investment and Post-COD Investment related costs applicable for inclusion in the MAAC associated with the following Specified Major Additions shall be included:

Specified Major Addition	Authorization Date	Termination Date
San Onofre Nuclear Generating Station Unit 2	09/07/83	-
San Onofre Nuclear Generating Station Unit 3	04/01/84	-
Balsam Meadow Hydro Electric Generating Plant	01/01/88	-
Devers-Valley-Serrano 500 kV Transmission Line	01/01/88	-
Sylmar-Pacific HVDC Intertie Expansion	-	-
Devers-Palo Verde No. 2 Transmission Line	-	-

NEW

j. Termination Date:

NEW

The Termination Date shall be the date on which the costs incurred thereafter for a Specified Major Addition shall no longer be applicable for inclusion in the MAAC.

4. Calculation of the Average Ownership Rate. Individual rates to reflect those Pre-COD Investment and Post-COD Investment related costs of owning each Specified Major Addition shall be calculated as authorized by the Commission. The Average Ownership Rate for each Specified Major Addition shall be determined from the following calculations:

CHANGE

a. The Forecast Period depreciation including decommissioning reserve expense;

b. Plus: The Forecast Period ad valorem taxes;

c. Plus: The Forecast Period taxes based on income, including the following tax adjustments:

1. The tax deductions resulting from items "a" and "b" above;
2. Investment tax credits;
3. The tax effect of the excess of liberalized depreciation over booked depreciation;
4. Interest charge deductions;
5. Other appropriate tax adjustments;

d. Plus: The Forecast Period return which shall be the Forecast Period rate base multiplied by the Company's system rate of return most recently authorized by the Commission.

NEW

e. The sum of "a" through "d" shall be multiplied by the most recently adopted retail jurisdictional allocation factor.

(Continued)

PRELIMINARY STATEMENT

(Continued)

K. MAJOR ADDITIONS ADJUSTMENT CLAUSE (MAAC) (Continued)

4. Calculation of the Average Ownership Rate (Continued)

f. The amounts in "e" above, increased to provide for Franchise Fees and Uncollectible Accounts, shall be divided by the sales subject to the MAAC estimated to be sold during the Forecast Period. The result shall be the Average Ownership Rate, expressed in cents per kilowatthour, as set forth below.

CHANGE

NEW

Specified Major Addition	Average Ownership Rate (¢/kWh)
San Onofre Nuclear Generating Station Unit 2	0.622
San Onofre Nuclear Generating Station Unit 3	0.648
Balsam Meadow Hydro Electric Generating Plant	0.059
Devers-Valley-Serrano 500 kV Transmission Line	—
Sylmar-Pacific HVDC Intertie Expansion	-
Devers-Palo Verde No. 2 Transmission Line	-

At such times as the Commission authorizes any adjustments which affect the amounts applicable for inclusion in the Average Ownership Rate, the Average Ownership Rate shall be appropriately revised.

CHANGE

5. Calculation of the Balancing Rate for Each Specified Major Addition. The Balancing Rate for each Specified Major Addition shall be calculated by dividing the estimated balance in the Major Additions Adjustment Account, plus the interest forecast to accrue during the amortization period, on the Revision Date (calculated in accordance with the procedure set forth in Paragraph 7), increased to provide for Franchise Fees and Uncollectible Accounts, by the sales subject to the MAAC estimated to be sold during the amortization period. The result shall be the Balancing Rate, expressed in cents per kilowatthour. The Balancing Rate associated with each Specified Major Addition authorized for inclusion in the MAAC is set forth below:

NEW

Specified Major Addition	Balancing Rate (¢/kWh)
San Onofre Nuclear Generating Station Unit 2	0.000
San Onofre Nuclear Generating Station Unit 3	0.000
Balsam Meadow Hydro Electric Generating Plant	0.000
Devers-Valley-Serrano 500 kV Transmission Line	0.000
Sylmar-Pacific HVDC Intertie Expansion	0.000
Devers-Palo Verde No. 2 Transmission Line	0.000

(Continued)

Southern California Edison
2244 Walnut Grove Avenue, Rosemead, California 91770

PRELIMINARY STATEMENT

(Continued)

K. MAJOR ADDITIONS ADJUSTMENT CLAUSE (MAAC) (Continued)

CHANGE

6. Major Additions Adjustment Billing Factor (MAABF). The MAABF shall be the sum of the Average Ownership Rates and the Balancing Rates for each Specified Major Addition. Such MAABF, expressed in cents per kilowatthour, shall be applied on a uniform cents-per-kilowatthour basis to all sales subject to the MAAC. The application of the MAABF to sales shall be as set forth on the applicable rate schedule.

The MAABF listed below have been, or are, in effect for the periods indicated:

Effective Date	Major Additions Adjustment Billing Factor (¢/kWh)
10/09/83	0.311
01/01/84	0.492
04/01/84	0.767
01/01/85	1.270
01/01/88	—

NEW

CHANGE

7. Major Additions Adjustment Account for Each Specified Major Addition. The Company shall maintain a Major Additions Adjustment Account (Balancing Account) for each Specified Major Addition. Entries to be made to these accounts at the end of each month will be determined from the following calculations:

a. Depreciation including decommissioning reserve expense as recorded during the month;

b. Plus: Ad valorem taxes as recorded during the month;

c. Plus: Taxes based on income, including appropriate tax adjustments, all as recorded during the month;

d. Plus: Return, which shall be one-twelfth of the rate of return authorized by the Commission for each Specified Major Addition multiplied by the average depreciated rate base, as recorded during the month;

CHANGE

e. Less: The sum of "a" through "d" multiplied by the most recently adopted resale jurisdictional allocation factor;

f. Less: The amount of revenue attributable to each Specified Major Addition. This amount of revenue shall be calculated by multiplying the sum of the Average Ownership Rate and Balancing Rate for each Specified Major Addition, times the kilowatthours sold during the month applicable to the MAABF, reduced to provide for Franchise Fees and Uncollectible Accounts.

If the above calculation produces a positive amount (undercollection), such amount will be debited to the Balancing Account in conjunction with the Specified Major Addition as approved by the Commission. If the calculation produces a negative amount (overcollection), such amount will be credited to the Balancing Account. Interest will accrue monthly to the Balancing Account by applying the Interest Rate to the average of the beginning and ending balance.

8. Calculation of the Average Noninvestment-Related Expense Rate. Individual rates to reflect certain noninvestment-related costs associated with each Specified Major Addition shall be calculated as authorized by the Commission. The Average Noninvestment-Related Expense Rate for each Specified Major Addition shall be determined from the following calculations:

a. The Forecast Period operation and maintenance expenses (excluding all costs recovered through the Company's Energy Cost Adjustment Clause or through the currently-effective base rates) appropriate for inclusion in the MAAC;

b. Plus: The Forecast Period pensions and benefits expense associated with the labor portion of "a" above;

c. Plus: The Forecast Period payroll tax expense associated with the labor portion of "a" above;

(Continued)

PRELIMINARY STATEMENT

(Continued)

K. MAJOR ADDITIONS ADJUSTMENT CLAUSE (MAAC) (Continued)

8. Calculation of the Average Noninvestment-Related Expense Rate. (Continued)

d. Plus: The Forecast Period property, liability, and replacement generation insurance expenses.

e. The sum of "a" through "d" shall be multiplied by the most recently adopted retail jurisdictional allocation factor.

f. The amount in "e" above, increased to provide for Franchise Fees and Uncollectible Accounts, shall be divided by the sales subject to the MAAC estimated to be sold during the Forecast Period. The result shall be the Average Noninvestment-Related Expense Rate, expressed in cents per kilowatthour, as set forth below:

NEW

Specified Major Addition	Average Noninvestment Related Expense Rate (¢/kWh)
San Onofre Nuclear Generating Station Unit 2	0.000
San Onofre Nuclear Generating Station Unit 3	0.000

9. Annual Major Additions Rate (AMAR). The AMAR shall be the sum of the Average Noninvestment-Related Expense Rates for each Specified Major Addition. Such AMAR, expressed in cents per kilowatthour, shall be applied on a uniform cents-per-kilowatthour basis to all sales subject to the MAAC. The application of the AMAR to sales shall be as set forth on the applicable rate schedule.

The AMAR listed below have been, or are, in effect for the periods indicated:

Effective Date	Annual Major Additions Rate (¢/kWh)
10/09/83	0.071
03/23/84	0.077
04/01/84	0.154
01/01/85	0.000

(Continued)

APPENDIX B

PLANT HELD FOR FUTURE USE GUIDELINES

1. This exhibit presents the analysis and recommendations of the Public Staff Division (PSD), Energy Operational Costs Branch. The purpose is to recommend a set of guidelines by which the reasonableness of including or maintaining items in Plant Held for Future Use (PHFU) can be judged. These guidelines would be applicable to all energy utilities under the Commission's jurisdiction.

2. At this time, the Commission has not set forth specific criteria by which to judge the reasonableness of including or maintaining items in PHFU. PHFU issues are decided on a case-by-case basis. For this reason, treatment of PHFU issues is not necessarily consistent among the energy utilities in California. PSD has developed this set of guidelines for use in determining the reasonableness of including or maintaining items in PHFU for energy utilities. The recommended guidelines are as follows:

a. All items in PHFU must have a specific plan for use.

b. The need for each item must be justified before being placed in PHFU.

c. If, at any time, the needs or plans for the use of an item change so that a specific plan for use no longer exists, the item shall be removed from PHFU.

d. The maximum time period for maintaining any item in PHFU prior to its inclusion in a construction budget is shown on the following table and varies from three to ten years depending on the type of plant.

e. If, after the allowed time period, an item has not been included in a construction budget, the item will be removed from PHFU until such time that it is included in a construction budget.

f. The maximum forecast period for a project in a construction budget will be no more than five years.

g. Therefore, the maximum time any item could be maintained in PHFU prior to the start of construction will be 8 to 15 years depending on the type of plant.

ELECTRIC AND GAS UTILITIES

Type of Plant	Time Period
Production Plant:	
Power Plant (New)	10 years
Transmission Plant:	
Transmission Line & Substation (related to new Power Plant)	10 years
Transmission Line & Substation (not related to new Power Plant)	5 years
Distribution Plant:	
Distribution Substation	5 years
Gas Storage:	5 years
General Plant:	3 years

3. A specific plan implies that the utility knows exactly what the item is going to be used for.

4. PSD believes, for the purposes above, that a construction budget project should: (1) have been reviewed by the utility for need and cost; and (2) be part of the capital budget prepared by the utility annually and authorized by the utility's management.

5. PSD acknowledges that there may be special cases where strict adherence to a set of guidelines such as listed above may not be appropriate. Such exceptions can be judged on their own merits on a case-by-case basis. In these cases, should the utility exceed the maximum time period for an item without inclusion in its capital budget, it must satisfactorily establish the following items in order to keep the item in PHFU:

a. There is still a definite plan and need to retain the item in PHFU;

b. Economic analysis justifies the retention; and

c. There are mitigating circumstances to require the retention.

6. It is desirable to establish criteria in order to minimize the amounts of PHFU to be included in rate base. As such, the adoption of the foregoing set of guidelines is necessary to provide utilities and ratepayers with reasonable ratemaking treatment of PHFU.

7. Nothing in this exhibit should be interpreted as precluding the ability of the ratepayers to recover gains on sales of plant that has at some time earned a return as PHFU.

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
OPERATING REVENUES AT PRESENT RATES
Thousands Of 1988 Dollars
Test Year 1988

Description	Adopted
Domestic	$895,665
Lighting-Sm & Med Power	972,160
Large Power	645,303
Agricultural & Pumping	77,901
Street & Area Lighting	53,607
Five Customer Groups and Santa Catalina Island	$2,644,636
TOU-Resale	64,639
Sequoia	13
Fringe	0
Net Edison	$2,709,288
SWP	0
MWD	7
Resale - Special	6,679
Subtotal	2,715,974
Other Operating Revenues	$51,416
Total Operating Revenues	$2,767,390

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
CALCULATION OF FRANCHISE FEES AND UNCOLLECTIBLES
Thousands Of 1988 Dollars
Test Year 1988

Description	Adopted
At Present Rates	
Revenues at Current Rates	$2,644,636
Uncollectible Factor	0.00214
Uncollectibles	$5,660
Revenues From Customers	$2,715,974
Franchise Requirement Factor	0.0073
Total Franchise Requirements	$19,827

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
TOTAL PRODUCTION EXPENSE
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Description	Adopted
Operation	
Steam	$72,608
Nuclear	91,037
Hydraulic	8,550
Other	8,356
Total Operation	$180,551
Maintenance	
Steam	134,277
Nuclear	76,422
Hydraulic	11,922
Other	8,869
Total Maintenance	$231,490
TOTAL PRODUCTION (1985$)	$412,042
Escalation Amounts, 1985 to 1988	
Labor	16,995
Non-Labor	23,901
Other	0
Total	$40,896
TOTAL PRODUCTION (1988$)	$452,937

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
STEAM PRODUCTION EXPENSE
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Account No.	Description	Adopted
	Operation	
500.0	Supervision and Engineering	$7,431
501.0	Fuel Related Expenses	25,080
502.0	Steam Expenses	14,091
505.0	Electric Expenses	6,856
506.0	Misc. Steam Power Expenses	18,975
507.0	Rents	175
	Total Operation	$72,608
	Maintenance	
510.0	Supervision and Engineering	19,480
511.0	Structures	6,736
512.0	Boiler Plant	65,390
513.0	Electric Plant	34,241
514.0	Miscellaneous Steam Plant	8,430
	Total Maintenance	$134,277
	TOTAL STEAM PRODUCTION (1985$)	$206,886
	Escalation Amounts, 1985 to 1988	
	Labor	7,025
	Non-Labor	12,987
	Other	0
	Total	$20,012
	TOTAL STEAM PRODUCTION (1988$)	$226,897

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
NUCLEAR PRODUCTION EXPENSE excl. PALO VERDE UNIT #3
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Account No.	Description	Adopted
	Operation	
517.0	Supervision and Engineering	$32,440
519.0	Coolants and Water	5,977
520.0	Steam Expenses	12,258
523.0	Electric Expenses	1,923
524.0	Misc. Nuclear Power Expenses	37,969
525.0	Rents	470
	Total Operation	$91,037
	Maintenance	
528.0	Supervision and Engineering	25,168
529.0	Structures	8,448
530.0	Reactor Plant Equipment	18,195
531.0	Electric Plant	11,176
532.0	Miscellaneous Nuclear Plant	13,435
	Total Maintenance	$76,422
	TOTAL NUCLEAR PROD. (1985$)	$167,459
	Escalation Amounts, 1985 to 1988	
	Labor	8,098
	Non-Labor	8,901
	Other	0
	Total	$16,999
	TOTAL NUCLEAR PROD. (1988$)	$184,458

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
HYDRAULIC PRODUCTION EXPENSE
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Account No.	Description	Adopted
	Operation	
535.0	Supervision and Engineering	$1,783
536.0	Water for Power	1,309
537.0	Hydraulic Expenses	2,104
538.0	Electric Expense	1,840
539.0	Misc. Hydro Expense Generation	1,311
540.0	Rents	203
	Total Operation	$8,550
	Maintenance	
541.0	Supervision and Engineering	1,099
542.0	Structures	1,102
543.0	Reservoirs, Dams and Waterways	2,069
544.0	Maintenance of Electric Plant	5,930
545.0	Miscellaneous Hydraulic Plant	1,722
	Total Maintenance	$11,922
	TOTAL HYDRO PRODUCTION (1985$)	$20,472
	Escalation Amounts, 1985 to 1988	
	Labor	1,073
	Non-Labor	1,047
	Other	0
	Total	$2,120
	TOTAL HYDRO PRODUCTION (1988$)	$22,592

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
OTHER POWER PRODUCTION EXPENSE
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Account No.	Description	Adopted
	Operation	
546.0	Supervision and Engineering	$979
548.0	Generation Expenses	2,489
549.0	Misc. Other Power Expenses	4,856
550.0	Rents	32
	Total Operation	$8,356
	Maintenance	
551.0	Supervision and Engineering	912
552.0	Maintenance of Structures	619
553.0	Maintenance of Electric Plant	6,792
554.0	Misc. Other Power Gen. Plant	546
	Total Maintenance	$8,869
	TOTAL OTHER PRODUCTION (1985$)	$17,225
	Escalation Amounts, 1985 to 1988	
	Labor	799
	Non-Labor	966
	Other	0
	Total	$1,765
	TOTAL OTHER PRODUCTION (1988$)	$18,990

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
TRANSMISSION EXPENSE
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Account No.	Description	Adopted
	Operation	
560.0	Supervision and Engineering	$7,034
561.0	Load Dispatching	3,081
562.0	Station Expenses	14,766
563.0	Overhead Line Expenses	1,135
564.0	Underground Line Expenses	32
565.0	Trans. of Elect. By Others	15,033
566.0	Misc. Transmission Expenses	3,742
567.0	Rents	529
	Total Operation	$45,352
	Maintenance	
568.00	Supervision and Engineering	4,179
569.00	Structures	2,059
570.00	Station Equipment	8,872
571.00	Overhead Lines	10,869
572.00	Underground Lines	94
573.00	Misc. Transmission Plant	3,918
	Total Maintenance	$29,991
	TOTAL TRANSMISSION (1985$)	$75,343
	Escalation Amounts, 1985 to 1988	
	Labor	4,014
	Non-Labor	2,362
	Other	0
	Total	$6,376
	TOTAL TRANSMISSION (1988$)	$81,719

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
DISTRIBUTION EXPENSE
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Account No.	Description	Adopted
	Operation	
580.0	Supervision and Engineering	$16,482
582.0	Station Expenses	8,592
583.0	Overhead Line Expenses	5,508
584.0	Underground Line Expenses	5,476
585.0	Street Lighting & Signal Sys.	1,196
586.0	Meter Expenses	11,567
587.0	Customer Installations	10,093
588.0	Misc. Distribution Expenses	17,229
589.0	Rents	1,188
	Total Operation	$77,331
	Maintenance	
590.00	Supervision and Engineering	9,004
591.00	Structures	4,071
592.00	Station Equipment	6,378
593.00	Overhead Services	24,330
594.00	Underground Lines	6,523
595.00	Line Transformers	5,343
596.00	Street Lighting & Signal Sys.	2,117
597.00	Meters	1,786
598.00	Misc. Distribution Plant	16,971
	Total Maintenance	$76,523
	TOTAL DISTRIBUTION (1985$)	$153,854
	Escalation Amounts, 1985 to 1988	
	Labor	9,735
	Non-Labor	6,723
	Other	0
	Total	$16,458
	TOTAL DISTRIBUTION (1988$)	$170,312

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
CUSTOMER ACCOUNTS EXPENSE
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Account No.	Description	Adopted
901.0	Supervision	$6,441
902.0	Meter Reading Expenses	21,987
903.0	Customer Records and Collectibles	61,353
904.0	Uncollectible Accounts	5,660
905.0	Misc. Customer Accounts Exp.	6,216
	TOTAL CUSTOMER ACCTS. (1985$)	$101,657
	Total (Less Uncollectibles)	$95,997
	Escalation Amounts, 1985 to 1988	
	Labor	7,363
	Non-Labor	2,035
	Other	0
	Total	$9,397
	TOTAL CUSTOMER ACCTS. (1988$)	$111,054
	Total (Less Uncollectibles)	$105,394

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
CUSTOMER SERVICE AND INFORMATIONAL EXPENSES
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Account No.	Description	Adopted
	Residential & Non-Residential Conservation, Service Planning, and Load Management Expenses	
907.0	Supervision	$482
908.0	Customer Assistance Expense	50,801
909.0	Informational & Instruct. Exp.	2,910
910.0	Miscellaneous	0
	TOTAL CUSTOMER SERVICES AND INFORMATIONAL (1985$)	$54,193
	Escalation Amounts, 1985 to 1988	
	Labor	1,837
	Non-Labor	2,105
	Other	0
	Total	$3,942
	TOTAL CUSTOMER SERVICES AND INFORMATIONAL (1988$)	$58,135

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
ADMINISTRATIVE & GENERAL EXPENSES
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Account No.	Description	Adopted
	Operation	
920.0	Administrative & Gen. Salaries	$109,273
921.0	Office Supplies and Expenses	24,208
922.0	Admin. & Gen. Transfer Credit	(26,162)
923.0	Outside Services Employed	7,112
924.0	Property Insurance	21,361
925.0	Injuries and Damages	23,965
926.0	Employee Pensions and Benefits	116,092
927.0	Franchise Requirements	19,827
928.0	Regulatory Commission Expenses	3,495
930.0	Other Misc. General Expenses	33,148
931.0	Rents	2,303
	Total Operation	$334,620
	Maintenance	
935.0	Maintenance of General Plant	11,683
	Total Maintenance	11,683
	TOTAL ADMIN. & GEN. (1985$)	$346,304
	Total (Less Franchise Req.)	$326,477
	Escalation Amounts, 1985 to 1988	
	Labor	11,591
	Non-Labor	5,985
	Other	0
	Total	$17,577
	TOTAL ADMIN. & GEN. (1988$)	$363,880
	Total (Less Franchise Req.)	$344,053

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
EXPENSE SUMMARY
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Description		Adopted
TOTAL NON-ESCALATED		
Steam Production	$206,886	
Nuclear Production	167,459	
Hydraulic Production	20,472	
Other Production	17,225	
Total Production		$412,042
Transmission		75,343
Distribution		153,854
Customer Accounts		101,657
Customer Service & Informational		54,193
Administrative and General		346,304
Additional Productivity		(22,832)
Total Non-Escalated (1985$)		$1,120,560
TOTAL ESCALATED		
Steam Production	226,897	
Nuclear Production	184,458	
Hydraulic Production	22,592	
Other Production	18,990	
Total Production		$452,937
Transmission		81,719
Distribution		170,312
Customer Accounts		111,054
Customer Service & Informational		58,135
Administrative and General		363,880
Additional Productivity		(24,722)
Total Escalated (1988$)		$1,213,315
TOTAL ESCALATION (1985$ to 1988$)		
Steam Production	20,012	
Nuclear Production	16,999	
Hydraulic Production	2,120	
Other Production	1,765	
Total Production		$40,896
Transmission		6,376
Distribution		16,458
Customer Accounts		9,397
Customer Service & Informational		3,942
Administrative and General		17,577
Additional Productivity		(1,890)
Total Escalation		$92,755

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
LABOR SUMMARY
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Description		Adopted
LABOR NON-ESCALATED (1985$)		
Steam Production	$62,285	
Nuclear Production	71,799	
Hydraulic Production	9,515	
Other Production	7,082	
Total Production		$150,681
Transmission		35,590
Distribution		86,309
Customer Accounts		65,278
Customer Service & Informational		16,286
Administrative and General		102,771
Additional Productivity		(9,124)
Total Non-Escalated Labor		$447,791
Labor Escalation Factor		1.11279
LABOR ESCALATED (1988$)		
Steam Production	69,310	
Nuclear Production	79,897	
Hydraulic Production	10,588	
Other Production	7,881	
Total Production		$167,676
Transmission		39,604
Distribution		96,044
Customer Accounts		72,640
Customer Service & Informational		18,123
Administrative and General		114,362
Additional Productivity		(10,153)
Total Escalated Labor		$498,296
LABOR ESCALATION (1985$ to 1988$)		
Steam Production	7,025	
Nuclear Production	8,098	
Hydraulic Production	1,073	
Other Production	799	
Total Production		$16,995
Transmission		4,014
Distribution		9,735
Customer Accounts		7,363
Customer Service & Informational		1,837
Administrative and General		11,591
Additional Productivity		(1,029)
Total Labor Escalation		$50,506

SOUTHERN CALIFORNIA EDISON COMPANY
NON-LABOR SUMMARY
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Description		Adopted
NON-LABOR NON-ESCALATED (1985$)		
Steam Production	$135,935	
Nuclear Production	93,174	
Hydraulic Production	10,957	
Other Production	10,111	
Total Production		$250,178
Transmission		24,720
Distribution		70,374
Customer Accounts		21,299
Customer Service & Informational		22,034
Administrative and General		62,649
Additional Productivity		(9,011)
Total Non-Escalated Non-Labor		$442,243
Non-Labor Escalation Factor		1.09553
NON-LABOR ESCALATED (1988$)		
Steam Production	148,922	
Nuclear Production	102,076	
Hydraulic Production	12,004	
Other Production	11,077	
Total Production		$274,079
Transmission		27,082
Distribution		77,097
Customer Accounts		23,334
Customer Service & Informational		24,139
Administrative and General		68,634
Additional Productivity		(9,872)
Total Escalated Non-Labor		$484,493
NON-LABOR ESCALATION (1985$ to 1988$)		
Steam Production	12,987	
Nuclear Production	8,901	
Hydraulic Production	1,047	
Other Production	966	
Total Production		$23,901
Transmission		2,362
Distribution		6,723
Customer Accounts		2,035
Customer Service & Informational		2,105
Administrative and General		5,985
Additional Productivity		(861)
Total Non-Labor Escalation		$42,250

SOUTHERN CALIFORNIA EDISON COMPANY
OTHER SUMMARY
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Description		Adopted
OTHER NON-ESCALATED (1985$)		
Steam Production	$8,665	
Nuclear Production	2,486	
Hydraulic Production	0	
Other Production	32	
Total Production		$11,183
Transmission		15,033
Distribution		(2,829)
Customer Accounts		15,080
Customer Service & Informational		15,873
Administrative and General		180,883
Additional Productivity		(4,697)
Total Non-Escalated Other		$230,526
Other Escalation Factor		1.0000
OTHER ESCALATED (1988$)		
Steam Production	8,665	
Nuclear Production	2,486	
Hydraulic Production	0	
Other Production	32	
Total Production		$11,183
Transmission		15,033
Distribution		(2,829)
Customer Accounts		15,080
Customer Service & Informational		15,873
Administrative and General		180,883
Additional Productivity		(4,697)
Total Escalated Other		$230,526
OTHER ESCALATION (1985$ to 1988$)		
Steam Production	0	
Nuclear Production	0	
Hydraulic Production	0	
Other Production	0	
Total Production		$0
Transmission		0
Distribution		0
Customer Accounts		0
Customer Service & Informational		0
Administrative and General		0
Additional Productivity		0
Total Other Escalation		$0

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
TAXES OTHER THAN ON INCOME
Thousands Of 1988 Dollars
Test Year 1988

Description	Adopted
Ad Valorem Taxes	
Ca., Ariz., N.M., Nev.	$82,298
Total Ad Valorem Taxes	82,298
Payroll Taxes	
Federal Insurance Contrib. Act	36,907
Federal Unemployment Insurance	588
State Unemployment Insurance	905
Total Payroll Taxes	38,400
Miscellaneous Taxes	
Superfund tax	1,000
Miscellaneous Taxes	(458)
Total Miscellaneous Taxes	542
Total Taxes OTOI (1987$)	$121,240

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
INCOME TAX ADJUSTMENTS
Thousands Of 1988 Dollars
Test Year 1988

Description	Adopted
California Income Tax Adjustments	
Tax Depreciation (liberalized)	$456,322
Nuclear Fuel Amort. (liberalized)	(106,581)
Fuel Oil Transp. Fac. (liberalized)	(4,584)
Interest Charges	273,583
Nucl. Fuel Lease Int. Cap.	13,318
A & G expenses - capitalized	52,941
Payroll Taxes Capitalized	14,933
Ad Valorem Taxes Capitalized	9,332
Use Tax Capitalized	5,558
Ad Valorem Lien Date Adjust.	1,853
Removal Costs	28,000
Right of Way Easement Amort.	1,218
Repair Allowance	13,000
Salvage Warehouse Exp.	300
Pension Reserves	0
Amortization of PV review costs	515
Interest Synchronization	(11,136)
	$748,573
Federal Income Tax Adjustments	
Tax Depreciation (liberalized)	342,848
Nuclear Fuel Amort. (liberalized)	(106,581)
Fuel Oil Transp. Fac. (liberalized)	(4,584)
Interest Charges	273,583
Nucl. Fuel Lease Int. Cap.	13,318
A & G expenses - capitalized	12,076
Payroll Taxes Capitalized	2,987
Ad Valorem Taxes Capitalized	1,866
Use Tax Capitalized	1,112
Ad Valorem Lien Date Adjust.	1,853
Removal Costs	19,000
Right of Way Easement Amort.	1,218
Repair Allowance	11,000
Salvage Warehouse Exp.	300
Pension Reserves	0
Amortization of PV review costs	515
Leased Property ITC	(221)
Total State Taxes on Income	0
Preferred Dividend Credit	832
Contrib. in Aid of Construct.	0
	$571,122

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
TAXES ON INCOME - ADOPTED RATES
Thousands Of 1988 Dollars
Test Year 1988

Description	Adopted
California Corporation Franchise Tax	
Operating Revenues	$2,767,390
Operating Expenses	1,213,315
Nuclear Decommissioning Exp.	0
Taxes Other Than On Income	121,240
Income Tax Adjustments	748,573
California Taxable Income	$684,262
CCFT Tax Rate	0.08994
TOTAL CCFT	$61,543
Federal Income Tax	
Operating Revenues	$2,767,390
Operating Expenses	1,213,315
Nuclear Decommissioning Exp.	0
Taxes Other Than On Income	121,240
CCFT	61,543
Income Tax Adjustments	571,122
Federal Taxable Income	$800,170
FIT Tax Rate	0.34
Federal Income Tax	$272,058
Inv.Credit-Rateable Flow-thru.	(14,670)
Accl. Amortization	(1,384)
ACRS	0
Superfund Tax	0
Total Federal Income Tax	$256,004

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
DEPRECIATION EXPENSE
Thousands Of 1988 Dollars
Test Year 1988

Description	Adopted
Steam Production	$80,759
Nuclear Production	$27,640
Hydraulic Production	$4,490
Other Production	$12,245
Transmission	$60,989
Distribution	$153,933
General	$39,349
Experimental Plant	8,358
Subtotal	$387,763
Amort. of PV review costs	515
Nuclear decommissioning	0
Total Depreciation Expense	$388,278

Depreciation expense embedded in other accounts

Other Depreciation (General)	1,411
Fuel Oil Transportation Facility	4,584
Total Depreciation Expense	5,995

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
DEPRECIATION RESERVE
Thousands Of 1988 Dollars
Test Year 1988

Description	Adopted
Depreciation Reserve - BOY	
Steam Production	$949,636
Nuclear Production	150,947
Hydraulic Production	113,168
Other Production	186,219
Transmission	547,836
Distribution	1,319,333
General	112,906
Experimental Plant	26,540
Retirement work-in-progress	(11,048)
Nuclear decommissioning	0
Other depr. (General)	5,936
Fuel Oil Transp. Fac.	44,476
Depreciation Reserve - BOY	$3,445,949
Other Adjustments (excl. Depr. expense)	
Steam Production	3,829
Nuclear Production	276
Hydraulic Production	374
Other Production	40
Transmission	6,083
Distribution	49,220
General	9,233
Experimental Plant	122
Retirement work-in-progress	0
Nuclear decommissioning	0
Other depr. (General)	1,112
Fuel Oil Transp. Fac.	12
Other Adjustments (excl. depr.)	70,300
Depreciation Reserve - EOY	
Steam Production	1,026,566
Nuclear Production	178,311
Hydraulic Production	117,284
Other Production	198,424
Transmission	602,742
Distribution	1,424,046
General	143,022
Experimental Plant	34,776
Retirement work-in-progress	(11,048)
Nuclear decommissioning	0
Other depr. (General)	6,235
Fuel Oil Transp. Fac.	49,048
Depreciation Reserve - EOY	3,769,407
Depreciation Reserve - Wtd. avg.	$3,607,678

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
PLANT IN SERVICE - EOY
Thousands Of 1988 Dollars
Test Year 1988

Description	Adopted
Plant in Service - BOY	
Intangible	$113
Production Plant	
Steam	1,899,064
Nuclear	637,078
Hydraulic	283,398
Other Production	386,318
Total Production	$3,205,858
Transmission Plant	1,756,685
Distribution Plant	3,886,420
General Plant	710,153
Total Plant in Service : BOY	9,559,229
Plant in Service - Net Additions	
Intangible	$0
Production Plant	
Steam	50,194
Nuclear	42,603
Hydraulic	34,893
Other Production	12,526
Total Production	$140,216
Transmission Plant	148,673
Distribution Plant	322,811
General Plant	85,340
Total Net Additions	697,040
Plant in Service - EOY	
Intangible	$113
Production Plant	
Steam	1,949,258
Nuclear	679,681
Hydraulic	318,291
Other Production	398,844
Total Production	$3,346,074
Transmission Plant	1,905,358
Distribution Plant	4,209,231
General Plant	795,493
Total Plant in Service : EOY	10,256,269

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
PLANT IN SERVICE - WTD. AVG.
Thousands Of 1988 Dollars
Test Year 1988

Description	Adopted
Plant in Service - BOY	
Intangible	$113
Production Plant	
Steam	1,899,064
Nuclear	637,078
Hydraulic	283,398
Other Production	386,318
Total Production	$3,205,858
Transmission Plant	1,756,685
Distribution Plant	3,886,420
General Plant	710,153
Total Plant in Service : BOY	9,559,229
Plant in Service - Weighted Average Net Additions	
Intangible	$0
Production Plant	
Steam	32,849
Nuclear	54,099
Hydraulic	9,616
Other Production	10,975
Total Production	$107,539
Transmission Plant	70,367
Distribution Plant	161,888
General Plant	59,098
Total Wtd. Avg. Net Additions	398,892
Total Plant in Service - Weighted Average	
Intangible	$113
Production Plant	
Steam	1,931,913
Nuclear	691,177
Hydraulic	293,014
Other Production	397,293
Total Production	$3,313,397
Transmission Plant	1,827,052
Distribution Plant	4,048,308
General Plant	769,251
Total Plant in Service : Wtd. Avg.	9,958,121

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
OTHER FIXED CAPITAL
Thousands Of 1988 Dollars
Test Year 1988

Description	Adopted
Nuclear Fuel	
Nuclear Fuel - BOY	$0
Nuclear Fuel - Net Additions	0
Nuclear Fuel - EOY	0
Nuclear Fuel - Wtd. Avg. Net Additions	0
Nuclear Fuel - Wtd. Avg.	0
Unclassified Electric Plant	
Unclass. Elect. Plant - BOY	293,057
Unclass. Elect. Plant - Net Additions	(14,577)
Unclass. Elect. Plant - EOY	278,480
Unclass. Elect. Plant - Wtd. Avg. Net Ad	(57,910)
Unclass. Elect. Plant - Wtd. Avg.	235,147
Plant Held for Future Use	
PHFU - BOY	116,948
PHFU - Net Additions	7,221
PHFU - EOY	124,169
PHFU - Wtd. Avg. Net Additions	3,606
PHFU - Wtd. Avg.	120,554

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
WEIGHTED AVERAGE DEPRECIATED RATE BASE
Thousands Of 1988 Dollars
Test Year 1988

Description	Adopted
FIXED CAPITAL @ BEGINNING OF YEAR	
Plant in Service	9,559,229
Nuclear Fuel	0
Unclassified Elect. Plant	293,057
PHFU	116,948
Total Fixed Capital - BOY	9,969,234
WTD. AVG. NET ADDITIONS	
Plant in Service	398,892
Nuclear Fuel	0
Unclassified Elect. Plant	(57,910)
PHFU	3,606
Total Wtd. Avg. Additions	344,588
Tot. Wtd. Avg. Fixed Capital	10,313,822
ADJUSTMENTS	
Cust. Adv. for Construction	(58,907)
Total Adjustments	(58,907)
WORKING CAPITAL	
Fuel Stock - Coal / Misc.	0
Materials & Supplies	118,343
Working Cash	(11,967)
Total Working Capital	106,376
Tot. Before Ded. for Reserves	10,361,291
DEDUCTIONS FOR RESERVES	
Wtd. Avg.Depreciation Reserve	3,607,678
Taxes Def. - Acc. Amort.	3,436
Taxes Def. - ACRS	325,594
Taxes Def. - Ref. Ret. Debt	69,689
Unfunded Pension Reserve	36,575
Total Ded. for Reserves	4,042,972
Weighted Average Depreciated Rate Base	6,318,318

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
DETERMINATION OF AVERAGE AMOUNTS OF WORKING
CASH CAPITAL SUPPLIED BY INVESTORS
Thousands Of 1988 Dollars
Test Year 1988

Description	Adopted
Operational Cash Requirements	
Cash	$2,633
Special Deposits	481
Working Funds	2,892
Total	$6,006
Less: Amounts Not Supplied By Investors	
Accrued Vacation & Empl. Witholdings	37,447
Credit recd. for capitlized supplies	39,322
Total	$76,769
Subtotal, Total Company	($70,763)
Electric Department Allocation Percentag	100%
Electric Department Allocation	(70,763)
Prepayments - Electric Department	0
Misc. Deferred Credits - Electric	0
Total Operational Cash Requirement	($70,763)
Plus: Average Amount Required	
Avg. Amt. Req. as a Result of Paying Expenses in Advance of Collecting Revenues	58,796
Total	$58,796
Average Net Amount of Working Cash Capital Supplied by Investors	($11,967)

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
DEVELOPMENT OF AVERAGE LAG IN PAYMENT OF EXPENSES
Thousands Of 1988 Dollars
Test Year 1988

Description	Expense	Average Lag Days	Product
	(A)	(B)	(C=AxB)
Fed. Income Tax	$231,384	121.19	28041481
FIT: SIT Ded. Ti	0	121.19	0
FIT: SIT Ded. Ti	0	486.19	0
State Income Tax	54223	83.59	4532504
Fed. Misc. Tax	0	0.00	0
Franchise Requir	35694	269.15	9606969
Fuel Oil	67819	16.36	1109519
Coal	125669	31.24	3925900
Natural Gas Purc	531021	37.36	19838945
Nuclear Fuel	162863	75.25	12255441
Purchased Power	1304150	38.15	49753323
Company Labor	498296	12.00	5979555
Property Insuran	20563	0.00	0
Injuries and Dam	22711	0.00	0
Pension Expense	109008	0.00	0
Ad Val.Tax - Ari	1930	210.43	406130
Ad Val.Tax - Nev	961	-61.36	-58967
Ad Val.Tax - New	1818	51.55	93718
Goods and Servic	497389	29.27	14558564
Materials From S	39861	0.00	0
Depreciation	388278	0.00	0
Ad Val.Tax - CA	77589	37.44	2904932
FICA Tax	36907	6.62	244325
Unemp. Tax - Fed	588	75.22	44251
Unemp. Tax - Cal	905	73.49	66518
Misc. taxes	-458	0.00	0
SIT - Az.,NM,Uta	163	126.78	20699
Hazardous Waste	320	363.50	116320
Deferred Income	67301	0.00	0
Adj. to ERTA Tax	-67301	121.19	-8156208
TOTAL	4209654		145283917

Exp. Lag Days	34.51	= (C)/(A)
Revenue Lag Days	39.61	
Adj. to Rate Bas	58,796	
Rate Base Factor	6,259,523	
New Rate Base	$6,318,318	

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
SUMMARY OF EARNINGS AT ADOPTED PRESENT RATE
REVENUES AND EXPENSES
(Thousands Of 1988 Dollars Unless Otherwise Indicated
Test Year 1988

Description	Adopted
Operating Revenues	
Revenues	$2,767,390
Total Operating Revenues	$2,767,390
Operating Expenses	
Production	412,042
Transmission	75,343
Distribution	153,854
Customer Accounts	95,997
Uncollectibles	5,660
Customer Service & Informational	54,193
Administrative & General	326,477
Franchise Requirements	19,827
Additional Productivity	(22,832)
Subtotal (1985 Dollars)	$1,120,560
Labor Escalation Amount	50,506
Non-Labor Escalation Amount	42,250
Subtotal (1988 Dollars)	$1,213,315
Depreciation	388,278
Nuclear Decommissioning Exp.	0
Taxes Other Than On Income	121,240
CA Corporation Franchise Tax	61,543
Federal Income Tax	256,004
Total Operating Expenses	$2,040,380
Net Operating Income	$727,010
Rate Base	6,318,318
Rate of Return (Total System)	11.51%

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - CPUC Jurisdiction
SUMMARY OF EARNINGS AT ADOPTED PRESENT RATE
REVENUES AND EXPENSES
(Thousands Of 1988 Dollars Unless Otherwise Indicated
Test Year 1988

Description	Jurisdictional Factors	Adopted
Operating Revenues		
Revenues	0.9764	$2,702,183
Total Operating Revenues		2,702,183
Operating Expenses		
Production	0.9805	404,007
Transmission	0.9818	73,968
Distribution	0.9985	153,623
Customer Accounts	0.9998	95,978
Uncollectibles	1.0000	5,660
Cust. Serv. & Inform.	1.0000	54,193
Administrative & Gen.	0.9891	322,918
Franchise Requirements	0.9983	19,793
Additional Productivity	0.9884	(22,567)
Subtotal (1985 Dollars)		$1,107,572
Labor Escalation Amount	0.9884	49,920
Non-Labor Escl. Amount	0.9884	41,759
Subtotal (1988 Dollars)		$1,199,252
Depreciation	0.9858	382,765
Nuclear Decommissioning	1.0000	0
Taxes Other Than On Inc	0.9872	119,689
CA Corporation Franchis	0.9880	57,890
Federal Income Tax	0.9880	242,907
Total Operating Expenses		$2,002,502
Net Operating Income		$699,681
Rate Base	0.9873	6,238,076
Rate of Return		11.22%

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - CPUC Jurisdiction
ADOPTED SUMMARY OF EARNINGS
(Thousands Of 1988 Dollars Unless Otherwise Indicated
Test Year 1988

Description	
Operating Revenues	
Adopted Present Rate Revenues	$2,702,183
Authorized incr. in Revenues (*)	(48,889)
Subtotal	2,653,294
Authorized TOU meter charges (*)	370
Total Operating Revenues	$2,653,663
Operating Expenses	
Production	444,105
Transmission	80,227
Distribution	170,056
Customer Accounts	105,373
Uncollectibles	5,555
Cust. Serv. & Inform.	58,135
Administrative & Gen.	340,303
Franchise Requirements	19,437
Additional Productivity	(24,435)
Subtotal (1988 Dollars)	$1,198,757
Depreciation	382,765
Nuclear Decommissioning Exp.	0
Taxes Other Than On Income	119,689
CA Corporation Franchise Tax	53,538
Federal Income Tax	227,933
Total Operating Expenses	$1,982,681
Net Operating Income	$670,613
Rate Base	6,238,076
Rate of Return	10.75%

(*) AUTH. CHANGE IN OPERATING REVENUES : ($48,519)

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
DEVELOPMENT OF THE NET-TO-GROSS MULTIPLIER
Test Year 1988

Description	(A)	(B)	(C=A*B)
Gross Operating Revenues			1.000000
Less: Uncoll.	0.002140	1.000000	0.002140
			0.997860
Less: Franchise	0.007300	1.000000	0.007300
			0.990560
Less: S.I.T.	0.089940	0.990560	0.089091
			0.901469
Less: F.I.T.	0.340000	0.901469	0.306499
Net Operating Revenues			0.594970
Uncoll. & F.F. Factor			1.009514
State & Fed. Tax Factor			1.664892
N-T-G Multiplier			1.680758

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department
ESCALATION FACTORS - Total Company
COST OF CAPITAL - CPUC Jurisdiction
Test Year 1988

Description		Adopted
LABOR -----------> ESCALATION FACTORS	1986	3.880%
	1987	3.500%
	1988	3.500%
	1989	4.840%
	1990	4.720%
NON-LABOR --------> ESCALATION FACTORS	1986	1.880%
	1987	2.990%
	1988	4.410%
	1989	4.640%
	1990	4.860%
OTHER ----------->	ALL YEARS	0.000%

COMPOSITE ESCALATION FACTORS

LABOR	1985 TO 1988	11.279%
NON-LABOR	1985 TO 1988	9.553%
OTHER	1985 TO 1988	0.000%

	COST	CAPITALIZATION	WTD. COST
Debt	9.22%	47.00%	4.33%
Pref. Stock	7.88%	7.00%	0.55%
Common equity	12.75%	46.00%	5.87%
Auth. Return on Rate Base (CPUC Jurisdiction) :			10.75%

ATTRITION YEAR 1989

	Expenses for AY1989 in 000's of 1988$	Expenses for AY1989 in 000's of 1988$ (Calif.)	Transfer of Other Expenses to Labor/ Non-Labor	Expenses for AY1989 in 000's of 1988$ for Attrition purposes
	A D O P T E D	I N	G R C	
Production (Juris. Alloc. Factor =			0.9805	
Labor	167,676	164,406	0	164,406
Non Labor	274,079	268,734	10,965	279,699
Other	11,183	10,965	(10,965)	0
	452,937	444,105	0	444,105
Transmission (Juris. Alloc. Factor =			0.9818	
Labor	39,604	38,881	0	38,881
Non Labor	27,082	26,587	14,759	41,346
Other	15,033	14,759	(14,759)	0
	81,719	80,227	0	80,227
Distribution (Juris. Alloc. Factor =			0.9985	
Labor	96,044	95,900	0	95,900
Non Labor	77,097	76,982	(2,825)	74,157
Other	(2,829)	(2,825)	2,825	0
	170,312	170,056	0	170,056
Customer Accounts (Juris. Alloc. Factor			0.9998	
Labor	72,640	72,626	0	72,626
Non Labor	23,334	23,329	9,418	32,747
Other	15,080	15,077	(9,418)	5,658
	111,054	111,032	0	111,032
Cust.Serv.&Info. (Juris. Alloc. Factor			1.0000)	
Labor	18,123	18,123	0	18,123
Non Labor	24,139	24,139	0	24,139
Other	15,873	15,873	0	15,873
	58,135	58,135	0	58,135
Admin. & Gen. (Juris. Alloc. Factor =			0.9891	ERR
Labor	114,362	113,116	52,697	165,812
Non Labor	68,634	67,886	102,814	170,701
Other	180,883	178,912	(155,511)	23,401
	363,880	359,914	(0)	359,914

	Expenses for AY1989 in 000's of 1988$	Expenses for AY1989 in 000's of 1988$ (Calif.)	Transfer of Other Expenses to Labor/ Non-Labor	Expenses for AY1989 in 000's of 1988$ for Attrition purposes
	A D O P T E D	I N	G R C	
Productivity Adj. (Juris. Alloc. Factor			0.9884	
Labor	(10,153)	(10,035)	0	(10,035)
Non Labor	(9,872)	(9,757)	(4,643)	(14,400)
Other	(4,697)	(4,643)	4,643	0
	(24,722)	(24,435)	0	(24,435)
Nucl. Refuel. Exp. (Juris. Alloc. Facto			0.9805	
Labor	(2,130)	(2,088)	0	(2,088)
Non Labor	(25,046)	(24,558)	0	(24,558)
Other	0	0	0	0
	(27,176)	(26,646)	0	(26,646)
TOTAL O&M EXPENSES				
Labor	496,166	490,928	52,697	543,625
Non Labor	459,447	453,343	130,489	583,831
Other	230,526	228,117	(183,185)	44,932
	1,186,139	1,172,388	0	1,172,388

Labor Base for AY 1989 in 1988$ (Adopted in GRC)	$543,625	
1988 Labor Escalation (estimated in GRC)	3.50%	
1987 Labor Escalation (estimated in GRC)	3.50%	
1986 Labor Escalation (estimated in GRC)	3.88%	
1986 Labor Escalation (use recorded)	3.88%	
1987 Labor Escalation (use recorded)	3.50%	
1988 Labor Escalation (use updated estimate)	3.50%	
1989 Labor Escalation (use updated estimate of CPI-Wage Earners)	4.84%	
Labor Base for AY 1989 in 1989$	569,936	
Labor Escalation for AY 1989 in 1989$	26,311	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.009514	
Increase in Revenue Requirement	26,562	(1)

Non-Labor Base for AY 1989 in 1988$ (Adopted in GRC	583,831	
1988 Non-Labor Escalation (estimated in GRC)	4.41%	
1987 Non-Labor Escalation (estimated in GRC)	2.99%	
1986 Non-Labor Escalation (estimated in GRC)	1.88%	
1986 Non-Labor Escalation (recorded)	1.88%	
1987 Non-Labor Escalation (recorded)	2.99%	
1988 Non-Labor Escalation (use updated estimate)	4.41%	
1989 Non-Labor Escalation (use updated estimate)	4.64%	
Non-Labor Base for AY 1989 in 1989$	610,921	
Non-Labor Escalation for AY 1989 in 1989$	27,090	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.009514	
Increase in Revenue Requirement	27,348	(2)

Nuclear Refueling Expense (Juris. Alloc 0.9805)

Increase in Labor expense	(2,130)	
Increase in Non-Labor expense	(25,046)	
Increase in Other expense	0	
Increase in Nuclear Refueling Expense	(27,176)	
Increase in Nuclear Refueling Expense (Calif)	(26,646)	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.009514	
Increase in Revenue Requirement	(26,900)	(3)

Depreciation Exp. (Juris. Alloc. Factor 0.9858)

System avg. Depreciation Rate (Adopted in GRC)	3.9593%	
Increase in Wtd. Avg. Plant in Service for AY1989 (Adopted in GRC)	555,614	
Increase in Depreciation expense	21,998	
Increase in Depreciation expense (Calif.)	21,686	
Net-to-Gross Multiplier (Adopted in GRC)	1.680758	
Increase in Revenue Requirement	36,449	(4)

Ad Valorem Taxes (Juris. Alloc. Factor 0.9872)			
System avg. Ad Valorem Tax Rate (Adopted in GRC)		0.8024%	
Increase in AY1989 EOY Plant in Service from TY1988 EOY Plant in Service (Adopted in GRC)		449,906	
Increase in Ad Valorem Taxes		3,610	
Increase in Ad Valorem Taxes (Calif.)		3,564	
Uncoll. & Franchise Fee Factor (Adopted in GRC)		1.009514	
Increase in Revenue Requirement		3,598	(5)

Accel. Amort. (Juris. Alloc. Factor = 0.9880)			
Attrition Year 1989 (Adopted in GRC)		(1,384)	
Test Year 1988 (Adopted in GRC)		(1,384)	
Increase in Accel. Amortization		0	
Increase in Accel. Amortization (Calif.)		0	
Net-to-Gross Multiplier (Adopted in GRC)		1.680758	
Increase in Revenue Requirement		0	(6)

State Tax Depr. (Juris. Alloc. Factor = 0.9880)			
State Tax Depr. Rate (Adopted in GRC)		4.4492%	
Increase in AY1989 EOY Plant in Service from TY1988 EOY Plant in Service (Adopted in GRC)		449,906	
Increase in State Tax Depreciation		20,017	
Increase in State Tax Depreciation (Calif.)		19,777	
Increase in CCFT (Tax Rate =	8.9940%	(1,779)	
Increase in FIT (Tax Rate =	34.0000%	605	
Increase in State & Federal Taxes		(1,174)	
Net-to-Gross Multiplier (Adopted in GRC)		1.680758	
Increase in Revenue Requirement		(1,973)	(7)

Federal Tax Depr. (Juris. Alloc. Factor 0.9880)			
Federal Tax Depr. Rate (Adopted in GRC)		3.3428%	
Increase in AY1989 EOY Plant in Service from TY1988 EOY Plant in Service (Adopted in GRC)		449,906	
Increase in Federal Tax Depreciation		15,040	
Increase in Federal Tax Depreciation (Calif.)		14,859	
Increase in Federal Taxes (Tax Rate	34.0000%	(5,052)	
Net-to-Gross Multiplier (Adopted in GRC)		1.680758	
Increase in Revenue Requirement		(8,491)	(8)

ITC Normalized (Juris. Alloc. Factor = 0.9880) (Applicable to IRC Sec. 46(f)(2) utilities only.)		
Attrition Year 1989 (Adopted in GRC)	(13,327)	
Test Year 1988 (Adopted in GRC)	(14,670)	
Increase in ITC normalized	1,343	
Increase in ITC normalized (Calif.)	1,327	
Net-to-Gross Multiplier (Adopted in GRC)	1.680758	
Increase in Revenue Requirement	2,230	(9)

Interest Synchro. (Juris. Alloc. Factor 0.9880) (Applicable to IRC Sec. 46(f)(2) utilities only.)			
ITC Normalized in TY1988 (from above)		14,670	
Wtd. cost of Long Term Debt (Adopted in AY1989)		4.33%	
Increase in CCFT interest		635	
Increase in CCFT (Tax Rate =	8.9940%	(57)	
Increase in FIT (Tax Rate =	34.0000%	19	
Increase in State & Federal Taxes		(38)	
Increase in State & Federal Taxes (Calif.)		(37)	
Net-to-Gross Multiplier (Adopted in GRC)		1.680758	
Increase in Revenue Requirement		(63)	(10)

Rate Base (Juris. Alloc. Factor = 0.9873)

Wtd. avg. Depr Rate Base for TY1988 (Adopted in GRC	6,318,318
Plant in Service (Adopted in GRC)	
Wtd. avg. Additions for TY1988	(398,892)
Net Additions for TY1988	697,040
Wtd. avg. Additions for AY1989	257,466
Unclassified Electric Plant (Adopted in GRC)	
Wtd. avg. Additions for TY1988	57,910
Net Additions for TY1988	(14,577)
Wtd. avg. Additions for AY1989	(3,525)
PHFU (Adopted in GRC)	
Wtd. avg. Additions for TY1988	(3,606)
Net Additions for TY1988	7,221
Wtd. avg. Additions for AY1989	(4,570)
Depreciation Reserve (Adopted in GRC)	
Wtd. avg. Depreciation Reserve for TY1988	3,607,678
Wtd. avg. Depreciation Reserve for AY1989	(3,940,175)
Taxes Deferred - ACRS (Adopted in GRC)	
Wtd. avg. Deferred Taxes - ACRS for TY1988	325,594
Wtd. avg. Deferred Taxes - ACRS for AY1989	(394,371)
Wtd. avg. Depr Rate Base for AY1989	6,511,512

Wtd. avg. Depr. Rate Base in TY1988 (Adopted in GRC	6,318,318
Wtd. avg. Depr. Rate Base in AY1989 (Adopted in GRC	6,511,512
Wtd. avg. Depr. Rate Base in TY 1988 (Calif.)	6,238,076
Wtd. avg. Depr. Rate Base in AY 1989 (Calif.)	6,428,816

Long-term Debt

Return on Debt in TY 1988 (Adopted in GRC)	9.22%
Debt capitalization in TY 1988 (Adopted in GRC)	47.00%
Wtd. cost of Debt for Test Year 1988	4.33%
Return on Debt in AY 1989 (Adopted in AY1989)	9.22%
Debt capitalization in AY 1989 (Adopted in AY1989)	47.00%
Wtd. cost of Debt for Attrition Year 1989	4.33%

Increase in Debt cost in Attrition Year 1989	8,259	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.009514	
Increase in Revenue Requirement	8,338	(11)

Preferred Stock

Return on Pref. Stock in TY 1988 (Adopted in GRC)	7.88%	
Pref.Stk. capitalization in TY1988 (Adopted in GRC)	7.00%	
Wtd. cost of Preferred Stock for Test Year 1988	0.55%	
Return on Pref. Stock in AY1989 (Adopted in AY1989)	7.88%	
Pref.Stk. capitalization AY1989 (Adopted in AY1989)	7.00%	
Wtd. cost of Preferred Stock for Att. Year 1989	0.55%	
Increase in Pref. Stock cost in Att. Year 1989	1,049	
Net-to-Gross Multiplier (Adopted in GRC)	1.680758	
Increase in Revenue Requirement	1,763	(12)

Common Equity

Return on Common Equity in TY 1988 (Adopted in GRC)	12.75%	
Com. Equity capitalization TY 1988 (Adopted in GRC)	46.00%	
Wtd. cost of Common Equity for Test Year 1988	5.87%	
Return on Common Equity AY 1989 (Adopted in AY1989)	12.75%	
Com. Eq. capitalization AY 1989 (Adopted in AY1989)	46.00%	
Wtd. cost of Common Equity for Att. Year 1989	5.87%	
Increase in Common Equity cost in Att. Year 1989	11,196	
Net-to-Gross Multiplier (Adopted in GRC)	1.680758	
Increase in Revenue Requirement	18,818	(13)

RATEBASE MONITORING

Wtd. avg. Depr.RateBase in TY1988 (Adopted in GRC)	6,318,318
Wtd. avg. Depr.RateBase in TY1988 (use updated est.	6,318,318
Wtd. avg. Depr.RateBase in AY1989 (Adopted in GRC)	6,511,512
Wtd. avg. Depr.RateBase in AY1989 (use updated est.	6,511,512

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
REVENUE REQUIREMENTS FOR ATTRITION YEAR 1989
Thousands Of 1989$

ITEM	ATTRITION YEAR 1989	
O & M EXPENSES :		
Labor Escalation	$26,562	(1)
Non-Labor Escalation	27,348	(2)
Nuclear Refueling expense	(26,900)	(3)
Total O&M Expenses	27,010	
CAPITAL RELATED ITEMS :		
Book Depreciation Expenses	36,449	(4)
Ad Valorem Taxes	3,598	(5)
Accelerated Amortization	0	(6)
State Tax Depreciation	(1,973)	(7)
Federal Tax Depreciation	(8,491)	(8)
ITC normalized	2,230	(9)
Interest Synchronization	(63)	(10)
Debt cost	8,338	(11)
Preferred Stock cost	1,763	(12)
Common Equity cost	18,818	(13)
Total Capital Related Items	60,669	
OTHER AUTHORIZED ITEMS :		
Jurisdictional Allocation change	9,800	
QF Program Adjustment	(200)	
Hydro Automation Adjustment	(356)	
Two-Shifting Adjustment	0	
Nuclear Regulatory Commission Fee	0	
Optional TOU meter charges	1,013	
Total Other Authorized Items	10,257	
ADD'L REVENUE REQUIREMENTS ---->	$97,936	
Exclude % attributable to Large Light & Power (To be adopted in OIR 86-10-001)	0.00%	
TOTAL ADD'L REVENUE REQUIREMENTS ---->	97,936	

ATTRITION YEAR 1990

	Expenses for AY1990 in 000's of 1988$	Expenses for AY1990 in 000's of 1988$ (Calif.)	Transfer of Other Expenses to Labor/ Non-Labor	Expenses for AY1990 in 000's of 1988$ for Attrition purposes
	ADOPTED IN GRC			
Nuclear Refueling (Juris. Alloc. Factor 0.9805)				
Labor	1,059	1,039	0	1,039
Non Labor	28,505	27,949	0	27,949
Other	0	0	0	0
	29,564	28,988	0	28,988
SONGS 2 Chemical Cleaning (Juris. Alloc 0.9805)				
Labor	110	108	0	108
Non Labor	1,691	1,658	0	1,658
Other	0	0	0	0
	1,801	1,765	0	1,765

Labor Base for nuclear refueling and SONGS 2 chemical cleaning for AY1990 in 1988$	$1,146
1988 Labor Escalation (estimated in GRC)	3.50%
1987 Labor Escalation (estimated in GRC)	3.50%
1986 Labor Escalation (estimated in GRC)	3.88%
1986 Labor Escalation (use recorded)	3.88%
1987 Labor Escalation (use recorded)	3.50%
1988 Labor Escalation (use recorded)	3.50%
1989 Labor Escalation (use updated estimate of CPI-Wage Earners)	4.84%
1990 Labor Escalation (use updated estimate of CPI-Wage Earners)	4.72%
Labor Base for nuclear refueling and SONGS 2 chemical cleaning for AY1990 in 1990$	1,259
Non-Labor Base for nuclear refueling and SONGS 2 chemical cleaning for AY1990 in 1988$	29,607
1988 Non-Labor Escalation (estimated in GRC)	4.41%
1987 Non-Labor Escalation (estimated in GRC)	2.99%
1986 Non-Labor Escalation (estimated in GRC)	1.88%
1986 Non-Labor Escalation (use recorded)	1.88%
1987 Non-Labor Escalation (use recorded)	2.99%
1988 Non-Labor Escalation (use recorded)	4.41%
1989 Non-Labor Escalation (use updated estimate)	4.64%
1990 Non-Labor Escalation (use updated estimate)	4.86%
Non-Labor Base for nuclear refueling and SONGS 2 chemical cleaning for AY1990 in 1990$	32,486

Total Labor & Non-Labor expenses for nuclear refueling and SONGS 2 chemical cleaning for AY1990 in 1990$	33,745	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.009514	
Increase in Revenue Requirement	34,066	(14)

Labor Base

Total Labor Base for AY 1990 in 1989$	569,936	
1989 Labor Escalation (estimated in GRC)	4.84%	
1988 Labor Escalation (estimated in AY1989)	3.50%	
1988 Labor Escalation (use recorded)	3.50%	
1989 Labor Escalation (use updated estimate)	4.84%	
1990 Labor Escalation (use updated estimate of CPI-Wage Earners)	4.72%	
Labor Base for AY 1990 in 1990$	596,837	
Labor Escalation for AY 1990 in 1990$	26,901	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.009514	
Increase in Revenue Requirement	27,157	(15)

Non-Labor Base

Non-Labor Base for AY 1989 (Adopted in AY1989)	$610,921	
1989 Non-Labor Escalation (estimated in GRC)	4.64%	
1988 Non-Labor Escalation (estimated in AY1989)	4.41%	
1988 Non-Labor Escalation (use recorded)	4.41%	
1989 Non-Labor Escalation (use updated estimate)	4.64%	
1990 Non-Labor Escalation (use updated estimate)	4.86%	
Non-Labor Base for AY 1990 in 1990$	640,612	
Non-Labor Escalation for AY 1990 in 1990$	29,691	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.009514	
Increase in Revenue Requirement	29,973	(16)

Depreciation Exp. (Juris. Alloc. Factor 0.9858)

System avg. Depreciation Rate (Adopted in GRC)	3.9593%	
Increase in Wtd. Avg. Plant in Service for AY1990 (Adopted in GRC)	441,711	
Increase in Depreciation expense	17,489	
Increase in Depreciation expense (Calif.)	17,240	
Net-to-Gross Multiplier (Adopted in GRC)	1.680758	
Increase in Revenue Requirement	28,977	(17)

Ad Valorem Taxes (Juris. Alloc. Factor 0.9872)

System avg. Ad Valorem Tax Rate (Adopted in GRC)	0.8024%	
Increase in AY1990 EOY Plant in Service from AY1989 EOY Plant in Service (Adopted in GRC)	435,585	
Increase in Ad Valorem Taxes	3,495	
Increase in Ad Valorem Taxes (Calif.)	3,450	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.009514	
Increase in Revenue Requirement	3,483	(18)

Accel. Amort. (Juris. Alloc. Factor = 0.9880)

Attrition Year 1990 (Adopted in GRC)	(24)	
Attrition Year 1989 (adopted in GRC)	(1,384)	
Increase in Accel. Amortization	1,360	
Increase in Accel. Amortization (Calif.)	1,344	
Net-to-Gross Multiplier (Adopted in GRC)	1.680758	
Increase in Revenue Requirement	2,258	(19)

State Tax Depr. (Juris. Alloc. Factor = 0.9880)

State Tax Depr. Rate (Adopted in GRC)		4.4492%	
Increase in AY1990 EOY Plant in Service from AY1989 EOY Plant in Service (Adopted in GRC)		435,585	
Increase in State Tax Depreciation		19,380	
Increase in State Tax Depreciation (Calif.)		19,148	
Increase in CCFT (Tax Rate =	8.9940%	(1,722)	
Increase in FIT (Tax Rate =	34.0000%	586	
Increase in State & Federal Taxes		(1,137)	
Net-to-Gross Multiplier (Adopted in GRC)		1.680758	
Increase in Revenue Requirement		(1,910)	(20)

Federal Tax Depr. (Juris. Alloc. Factor 0.9880)

Federal Tax Depr. Rate (Adopted in GRC)		3.3428%	
Increase in AY1990 EOY Plant in Service from AY1989 EOY Plant in Service (Adopted in GRC)		435,585	
Increase in Federal Tax Depreciation		14,561	
Increase in Federal Tax Depreciation (Calif.)		14,386	
Increase in Federal Taxes (Tax Rate	34.0000%	(4,891)	
Net-to-Gross Multiplier (Adopted in GRC)		1.680758	
Increase in Revenue Requirement		(8,221)	(21)

ITC Normalized (Juris. Alloc. Factor = 0.9880)
(Applicable to IRC Sec. 46(f)(2) utilities only.)

Attrition Year 1990 (Adopted in GRC)	(12,065)	
Attrition Year 1989 (adopted in GRC)	(13,327)	
Increase in ITC normalized	1,262	
Increase in ITC normalized (Calif.)	1,247	
Net-to-Gross Multiplier (Adopted in GRC)	1.680758	
Increase in Revenue Requirement	2,096	(22)

INTEREST SYNCHRO. (Juris. Alloc. Factor 0.9880)
(Applicable to IRC Sec. 46(f)(2) utilities only.))

ITC Normalized in AY1990 (from above)		12,065	
Wtd. cost of Long Term Debt (Adopted in AY1990)		4.33%	
Increase in CCFT interest		522	
Increase in CCFT (Tax Rate =	8.9940%	(47)	
Increase in FIT (Tax Rate =	34.0000%	16	
Increase in State & Federal Taxes		(31)	
Increase in State & Federal Taxes (Calif.)		(31)	
Net-to-Gross Multiplier (Adopted in GRC)		1.680758	
Increase in Revenue Requirement		(51)	(23)

Rate Base (Juris. Alloc. Factor =	0.9873)
Wtd. avg. Depr Rate Base for AY1989 (Adopted in GRC	6,511,512
Plant in Service (Adopted in GRC)	
Wtd. avg. Additions for AY1989	(257,466)
Net Additions for AY1989	449,906
Wtd. avg. Additions for AY1990	249,271
Unclassified Electric Plant (Adopted in GRC)	
Wtd. avg. Additions for AY1989	3,525
Net Additions for AY1989	(887)
Wtd. avg. Additions for AY1990	(2,638)
PHFU (Adopted in GRC)	
Wtd. avg. Additions for AY1989	4,570
Net Additions for AY1989	(9,151)
Wtd. avg. Additions for AY1990	0
Depreciation Reserve (Adopted in GRC)	
Wtd. avg. Depreciation Reserve for AY1989	3,940,175
Wtd. avg. Depreciation Reserve for AY1990	(4,288,895)
Taxes Deferred - ACRS (Adopted in GRC)	
Wtd. avg. Deferred Taxes - ACRS for AY1989	394,371
Wtd. avg. Deferred Taxes - ACRS for AY1990	(466,055)
Wtd. avg. Depr Rate Base for AY1990	6,528,238
Wtd. avg. Depr. Rate Base in Attrition Year 1989	6,511,512
Wtd. avg. Depr. Rate Base in Attrition Year 1990	6,528,238
Wtd. avg. Depr. Rate Base in AY 1989 (Calif.)	6,428,816
Wtd. avg. Depr. Rate Base in AY 1990 (Calif.)	6,445,330
Long-term Debt	
Return on Debt in AY 1989 (Adopted in AY1989)	9.22%
Debt capitalization in AY 1989 (Adopted in AY1989)	47.00%
Wtd. cost of Debt for Attrition Year 1989	4.33%
Return on Debt in AY 1990 (Adopted in AY1990)	9.22%
Debt capitalization in AY 1990 (Adopted in AY1990)	47.00%
Wtd. cost of Debt for Attrition Year 1990	4.33%

Increase in Debt cost in Attrition Year 1990	715	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.009514	
Increase in Revenue Requirement	722	(24)

Preferred Stock

Return on Pref. Stock in AY 1989 (Adopted in AY1989	7.88%	
Pref.Stk. capitalization AY 1989 (Adopted in AY1989	7.00%	
Wtd. cost of Preferred Stock for Test Year 1989	0.55%	
Return on Pref. Stock in AY 1990 (Adopted in AY1990	7.88%	
Pref.Stk. capitalization AY 1990 (Adopted in AY1990	7.00%	
Wtd. cost of Preferred Stock for Att. Year 1990	0.55%	
Increase in Pref. Stock cost in Att. Year 1990	91	
Net-to-Gross Multiplier (Adopted in GRC)	1.680758	
Increase in Revenue Requirement	153	(25)

Common Equity

Return on Com. Eq. in AY 1989 (Adopted in AY1989)	12.75%	
Com. Eq. capitalization AY 1989 (Adopted in AY1989)	46.00%	
Wtd. cost of Common Equity for Test Year 1989	5.87%	
Return on Com. Eq. in AY 1990 (Adopted in AY1990)	12.75%	
Com. Eq. capitalization AY 1990 (Adopted in AY1990)	46.00%	
Wtd. cost of Common Equity for Att. Year 1990	5.87%	
Increase in Common Equity cost in Att. Year 1990	969	
Net-to-Gross Multiplier (Adopted in GRC)	1.680758	
Increase in Revenue Requirement	1,629	(26)

RATEBASE TRACKING

Wtd. avg. Depr.Rate Base in TY1988 (Adopted in GRC)	6,318,318
Wtd. avg. Depr.Rate Base in TY1988 (estimated at the time of filing for AY 1989)	6,318,318
Wtd. avg. Depr.RateBase in TY1988 (recorded)	6,318,318
Wtd. avg. Depr.RateBase in AY1989 (Adopted in GRC)	6,511,512
Wtd. avg. Depr.RateBase in AY1989 (estimated at the time of filing for AY 1989)	6,511,512
Wtd. avg. Depr.RateBase in AY1989 (use updated est.	6,511,512
Wtd. avg. Depr.RateBase in AY1990 (Adopted in GRC)	6,528,238
Wtd. avg. Depr.RateBase in AY1990 (use updated est.	6,528,238

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
REVENUE REQUIREMENTS FOR ATTRITION YEAR 1990
Thousands Of 1990$

ITEM	ATTRITION YEAR 1990	
O & M EXPENSES :		
Nuclear Refueling & SONGS 2 Chem. Cleaning Exp.	34,066	(14)
Labor Escalation	$27,157	(15)
Non-Labor Escalation	29,973	(16)
Total O&M Expenses	91,196	
CAPITAL RELATED ITEMS :		
Book Depreciation Expenses	28,977	(17)
Ad Valorem Taxes	3,483	(18)
Accelerated Amortization	2,258	(19)
State Tax Depreciation	(1,910)	(20)
Federal Tax Depreciation	(8,221)	(21)
ITC normalized	2,096	(22)
Interest Synchronization	(51)	(23)
Debt cost	722	(24)
Preferred Stock cost	153	(25)
Common Equity cost	1,629	(26)
Total Capital Related Items	29,135	
OTHER AUTHORIZED ITEMS :		
Jurisdictional Allocation change	0	
QF Program Adjustment	(350)	
Nuclear Regulatory Commission Fee	0	
Optional TOU meter charges	1,560	
Total Other Authorized Items	1,210	
ADD'L REVENUE REQUIREMENTS ---->	$121,541	
Exclude % attributable to Large Light & Power (To be adopted in OIR 86-10-001)	0.00%	
TOTAL ADD'L REVENUE REQUIREMENTS ---->	121,541	

APPENDIX E

SOUTHERN CALIFORNIA EDISON COMPANY
TEST YEAR 1988 - CALIFORNIA JURISDICTION
REVENUE CHANGES ADOPTED FOR REVENUE ALLOCATION AND RATE DESIGN

ITEM	PRESENT RATE REVENUES **	ADOPTED REVENUES	REVENUE CHANGES
	($ million)	($ million)	($ million)
BASE:			
Base (GRC)	$ (see below)	$ (see below)	$ (see below)
DECOMM'G	0.000	100.327	100.327
* MAAC pre-COD tfr	0.000	501.626	501.626
* IMAAC PV-1,2 tfr	0.000	41.595	41.595
Palo Verde 3	0.000	0.000	0.000
PV Phase-in Proc	0.000	0.000	0.000
Subtotal	0.000	643.548	643.548
MAAC:			
SONGS 2,3 prCOD	819.154	0.000	(819.154)
* SONGS 2,3 poCOD	0.000	52.599	52.599
Amort.Bal.Ac.	0.000	8.240	8.240
* Sec.463 (in GRC)	0.000	55.271	55.271
IMAAC: PVNGS-1,2	46.440	0.000	(46.440)
OTHER OFFSETS:			
CLMAC	(5.805)	(16.770)	(10.965)
Haz.Waste	0.000	0.000	0.000
ECAC Regular	1,562.991	1,562.991	0.000
AER	179.956	179.956	0.000
Uran.	76.755	76.755	0.000
Chvrn Bal Amort.	147.706	201.886	54.180
ERAM Amort.	(87.720)	(87.720)	0.000
IMAAC Amort.	0.000	50.195	50.195
SONGS-1 Memo Ac	0.000	87.600	87.600
Tax Act'87 refd	0.000	(44.858)	(44.858)
Res.3053-E	0.000	(3.635)	(3.635)
Decommg Taxes	0.000	(10.725)	(10.725)
Total (all above)	2,739.477	2,755.333	15.856
GRC:			
* Results of Oper.	2,644.636	2,596.117	(48.519)
Other Revenues	57.547	57.547	0.000
Subtotal	2,702.183	2,653.664	(48.519)
CPUC remb.fees	7.740	7.740	0.000
GRAND TOTAL	5,449.400	5,416.737	(32.663)

Notes: * Amounts based on adopted ROE.
** Based on adjusted sales of 64,500.3 GWH.

(END OF APPENDIX E)

APPENDIX F
PAGE 1
SOUTHERN CALIFORNIA EDISON COMPANY
REVENUE ALLOCATION DETAIL

CUSTOMER GROUP	TARIFF SCHEDULE	SALES (MWH)	PRESENT EFFECTIVE REVENUE (000's)	PRESENT AVERAGE RATE ($/KWH)	ADOPTED EFFECTIVE REVENUE (000's)	ADOPTED AVERAGE RATE ($/KWH)	ADOPTED CHANGES AMOUNT (000's)	ADOPTED CHANGES PERCENT	ADOPTED CHANGES ($/KWH)
DOMESTIC		19,832,000	1,610,007	0.08118	1,689,171	0.08517	79,164	4.9%	0.03992
SMALL AND MEDIUM POWER									
	GS-1	3,822,600	396,017	0.10360	398,486	0.10424	2,470	0.6%	0.00646
	GS-2	17,059,800	1,503,966	0.08816	1,463,362	0.08578	(40,604)	-2.7%	-0.02380
	TC-1	130,000	11,594	0.08919	11,667	0.08974	72	0.6%	0.00556
	TOU-GS	785,800	65,299	0.08310	70,788	0.09008	5,490	8.4%	0.06986
SUBTOTAL		21,798,200	1,976,875	0.09069	1,944,303	0.08920	(32,572)	-1.6%	-0.01494
LARGE POWER									
	TOU-8:SEC	6,781,600	567,362	0.08366	546,088	0.08052	(21,274)	-3.7%	-0.03137
	TOU-8:PRI	10,406,400	785,268	0.07546	747,596	0.07184	(37,672)	-4.8%	-0.03620
	TOU-8:SUB	3,163,000	196,880	0.06224	183,841	0.05812	(13,039)	-6.6%	-0.04122
SUBTOTAL		20,351,000	1,549,510	0.07614	1,477,525	0.07260	(71,985)	-4.6%	-0.03537
AGRICULTURE		2,077,000	172,588	0.08309	171,093	0.08238	(1,495)	-0.9%	-0.00720
STREETLIGHTING		471,000	75,137	0.15953	69,362	0.14727	(5,775)	-7.7%	-0.12260
TOTAL		64,529,200	5,384,117	0.08344	5,351,454	0.08293	(32,663)	-0.6%	-0.00506

APPENDIX F
PAGE 2
SOUTHERN CALIFORNIA EDISON COMPANY
ALLOCABLE REVENUE REQUIREMENT 1/

CUSTOMER GROUP	ADJUSTED SALES (GWH)	REVENUE REQ (000's)	FACILITIES CHARGES (000's)	ECAC (000's)	AER (000's)	CLMAC (000's)	ERAM (000's)	MAAC (000's)	AMA (000's)	BASE (000's)
DOMESTIC	19,803.3	1,689,170.9	273.6	438,679.5	55,251.2	(5,148.9)	(2,772.5)	35,645.9	0.0	1,167,242.0
SM/MED POWER										
GS-1	3,822.6	398,486.4	0.0	125,381.3	10,665.1	(993.9)	(535.2)	6,880.7	0.0	257,088.4
GS-2	17,059.8	1,463,361.8	0.0	545,842.2	47,596.8	(4,435.5)	(2,388.4)	30,707.6	0.0	846,039.0
TC-1	130.0	11,666.5	0.0	4,165.2	362.7	(33.8)	(18.2)	234.0	0.0	6,956.6
TOU-GS	785.8	70,788.2	30.6	25,895.6	2,192.4	(204.3)	(110.0)	1,414.4	0.0	41,569.5
GROUP TOTAL	21,798.2	1,944,302.9	30.6	701,284.3	60,817.0	(5,667.5)	(3,051.7)	39,236.8	0.0	1,151,653.5
LARGE POWER										
TOU-8:SEC	6,781.6	546,088.0	0.0	221,201.6	18,920.7	(1,763.2)	(949.4)	12,206.9	0.0	296,471.5
TOU-8:PRI	10,406.4	747,595.6	0.0	313,533.3	29,033.9	(2,705.7)	(1,456.9)	18,731.5	0.0	390,459.5
TOU-8:SUB	3,163.0	183,841.4	0.0	86,184.5	8,824.8	(822.4)	(442.8)	5,693.4	0.0	84,403.9
GROUP TOTAL	20,351.0	1,477,525.0	0.0	620,919.4	56,779.3	(5,291.3)	(2,849.1)	36,631.8	0.0	771,334.9
AGRICULTURE	2,077.0	171,092.9	65.3	65,775.0	5,794.8	(540.0)	(290.8)	3,738.6	0.0	96,549.9
STREETLIGHTING	471.0	69,362.1	33,855.2	14,973.1	1,314.1	(122.5)	(65.9)	847.8	0.0	18,560.3
TOTAL	64,500.5	5,351,453.8	34,224.7	1,841,631.3	179,956.4	(16,770.1)	(9,030.1)	116,100.9	0.0	3,205,340.7

1/ Based on Appendix E.

APPENDIX G

TABLE 1

SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED MARGINAL COST REVENUE RESPONSIBILITY
TEST YEAR 1988
($ MILLIONS)

	MARGINAL ENERGY	GENERATION DEMAND	TRANS. DEMAND	DISTRIB. DEMAND	CUSTOMER	TOTAL	PERCENT
Domestic	592.1	355.6	164.9	331.5	140.4	1584.5	35.9
GS-1	120.5	92.3	41.9	74.4	15.6	344.6	7.8
GS-2	534.9	300.4	135.7	222.5	21.4	1214.9	27.5
PA-1	51.2	23.8	11.4	27.3	3.4	117.1	2.7
PA-2	10.5	5.1	2.3	4.3	0.1	22.3	0.5
Street Light	13.1	0.4	0.5	3.3	2.6	19.9	0.5
TOU-8 (Sec)	203.6	98.2	43.9	70.6	2.3	418.6	9.5
TOU-8 (Prim)	303.9	123.2	55.3	74.9	1.5	558.8	12.7
TOU-8 (Sub)	88.8	29.9	13.4	0.0	0.0	132.1	3.0
Total	1918.6	1028.9	469.3	808.7	187.4	4412.9	100.0

APPENDIX G

TABLE 2

Southern California Edison Company

ADOPTED MARGINAL DEMAND COST OF GENERATION

Test Year 1988

			$/KW
	COMBUSTION TURBINE		
(1)	Direct Investment		511.63
(2)	General Plant Loading	(L1*1.0385)	531.33
(3)	Working Cash Loading	(L2*1.017)	540.36
(4)	Annualized Cost including A&G Loading a/	(L3*0.1004)	54.25
	INTERCONNECT PLANT		
(5)	Direct Investment		70.63
(6)	General Plant Loading	(L5*1.0385)	73.35
(7)	Working Cash Loading	(L6*1.017)	74.60
(8)	Annualized Cost including A&G Loading a/	(L7*0.1029)	7.68
(9)	Subtotal - Total Investment	(L3+L7)	614.96
(10)	Subtotal - Annualized Cost	(L4+L8)	61.93
(11)	Fuel Inventory	(L9+$1.19)	63.12
(12)	O&M loading	(L10+$5.86)	68.98
(13)	Franchise Fees	(L11*1.0073)	69.48
(14)	Annual Marginal Demand Cost of Generation		69.48

a/ Real Economic Carrying Charge for combustion turbine and interconnection plant are 10.04% and 10.29% respectively.

APPENDIX G

TABLE 3

Southern California Edison Company

ADOPTED MARGINAL DEMAND COST OF TRANSMISSION

Test Year 1988

			$/KW
(1)	Direct Incremental Investment		249.40
(2)	General Plant Loading	(L1*1.0385)	259.00
(3)	Working Cash Loading	(L2*1.017)	263.40
(4)	Annualized Cost Including A&G Loading a/	(L3*0.1090)	28.71
(5)	O&M Loading	(L4+$4.15)	32.86
(6)	Franchise Fees	(L4*1.0073)	33.10
(7)	Annual Marginal Demand Cost of Transmission		33.10

a/ Real Economic Carrying Charge of 10.90%

APPENDIX G

TABLE 4

Southern California Edison Company

ADOPTED MARGINAL DEMAND COST OF DISTRIBUTION

Test Year 1988

			$/KW
(1)	Direct Incremental Investment		307.86
(2)	General Plant Loading	(L1*1.0385)	319.71
(3)	Working Cash Loading	(L2*1.017)	325.15
(4)	Annualized Cost Including A&G Loading [a]	(L3*0.1308)	42.53
(5)	O&M Loading	(L4+$10.16)	52.69
(6)	Franchise Fees	(L5*1.0073)	53.07
(7)	Customer contribution in aid to construction	(L6/1.01641)	52.22
(8)	Annual Marginal Demand Cost of Distribution: -- Secondary Voltage		52.22
(9)	-- Primary Voltage	(L8*86.3%)	45.06

[a] Real Economic Carrying Charge of 13.08%

APPENDIX G

TABLE 5

Southern California Edison Company

ADOPTED MARGINAL DEMAND COST
ADUSTED FOR LINE LOSSES
Test Year 1988

			$/KW/YR
(1)	SUBTRANSMISSION LEVEL		
(2)	Demand losses	1.033	
(3)	Generation (=$69.48*1.15*1.033)		82.54
(4)	Transmission		34.19
(5)	Total		116.73
(6)	PRIMARY LEVEL		
(7)	Demand Losses	1.086	
(8)	Generation		86.77
(9)	Transmission (=$33.10*1.086)		35.95
(10)	Distribution Primary		48.94
(11)	Total		171.66
(12)	SECONDARY LEVEL		
(13)	Demand Losses	1.107	
(14)	Generation		88.45
(15)	Transmission		36.64
(16)	Distribution Primary		49.88
(17)	Distribution Secondary (=$52.23*1.107)		57.81
(18)	Total		232.78

Capacity Response Ratio of Generation 1.15

APPENDIX G

TABLE 6

SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED MARGINAL ENERGY COSTS 1/
TEST YEAR 1988

DESCRIPTION	Summer On Peak	Summer Mid Peak	Summer Off Peak	Summer Average	Winter Mid Peak	Winter Off Peak	Winter Average	Annual
Marginal Fuel Cost (c/kWh)	2.33	2.30	2.22	2.26	2.32	2.24	2.27	2.27
Fuel Price ($/mBtu)	2.52	2.52	2.52	2.52	2.52	2.52	2.52	2.52
Incremental Energy Rate (IER) (Btu/kWh)	9238	9121	8798	8959	9221	8900	9022	9001
Startup and No-Load Adjustment (Btu/kWh)	2883	458	0	623	1647	0	433	624
Incremental Energy Rate (Btu/kWh)	12121	9579	8798	9582	10869	8900	9647	9626
Marginal Energy Cost (c/kWh)	3.05	2.41	2.22	2.41	2.74	2.24	2.43	2.43
Variable O&M (c/kWh)	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Generation Marginal Energy Cost (c/kWh)	3.35	2.71	2.52	2.71	3.04	2.54	2.73	2.73
Subtransmission								
Energy Loss Factor	1.03	1.028	1.025	1.027	1.028	1.024	1.026	1.026
Marginal Energy Cost (c/kWh)	3.46	2.79	2.58	2.79	3.12	2.60	2.80	2.80
Primary Level								
Energy Loss Factor	1.076	1.07	1.061	1.066	1.068	1.058	1.062	1.063
Marginal Energy Cost (c/kWh)	3.61	2.90	2.67	2.89	3.25	2.69	2.90	2.90
Secondary Level								
Energy Loss Factor	1.097	1.091	1.082	1.087	1.089	1.078	1.082	1.084
Marginal Energy Cost (c/kWh)	3.68	2.96	2.72	2.95	3.31	2.74	2.96	2.95

1/ Reflects revised TOU periods adopted in this decision, i.e., winter on peak period is combined with winter mid peak period

(End of Appendix G)

APPENDIX H

SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED AVOIDED ENERGY COSTS 1/
TEST YEAR 1988

	Summer				Winter			Annual Average
	On-Peak	Mid-Peak	Off-Peak	Average	Mid-Peak	Off-Peak	Average	
Marginal Energy Cost (c/kWh)	2.40	2.35	2.23	2.29	2.39	2.27	2.31	2.31
Incremental Energy Rate(IER) (Btu/kWh)	9531	9329	8843	9090	9468	9005	9180	9151
Startup and No-Load Adjustment (Btu/kWh)	2883	458	0	623	1647	0	625	624
IER (Btu/kWh)	12414	9787	8843	9713	11115	9005	9805	9775
Marginal Fuel Price ($/MMBtu)	2.52	2.52	2.52	2.52	2.52	2.52	2.52	2.52
Avoided Cost of Energy (c/kWh)	3.13	2.47	2.23	2.45	2.80	2.27	2.47	2.46
Variable O&M (c/kWh)	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Generation Level Avoided Energy Cost (c/kWh)	3.43	2.77	2.53	2.75	3.10	2.57	2.77	2.76
Subtransmission Level								
[illegible]gy Loss Factor	1.023	1.023	1.023	1.023	1.023	1.023	1.023	1.023
Avoided Energy Cost (c/kWh)	3.51	2.83	2.59	2.81	3.17	2.63	2.83	2.83
Primary Level								
Energy Loss Factor	1.026	1.026	1.026	1.026	1.026	1.026	1.026	1.026
Avoided Energy Cost (c/kWh)	3.52	2.84	2.59	2.82	3.18	2.64	2.84	2.84
Secondary Level								
Energy Loss Factor	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Avoided Energy Cost (c/kWh)	3.43	2.77	2.53	2.75	3.10	2.57	2.77	2.76

1/ Reflects revised TOU periods adopted in this decision, i.e., winter on peak period is combined with winter mid peak period

(End of Appendix H)

APPENDIX I

SOUTHERN CALIFORNIA EDISON COMPANY

RATE DESIGN APPENDIX

NOTE: Rates in this appendix reflect PUC surcharge fee of $.00012/kWh which is added after rate design.

APPENDIX I
PAGE 1
SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED RESIDENTIAL RATES

EFFECTIVE 01-01-88
($/KWH)

SCHEDULE	D	TOU-D a/	
SEASON	ANNUAL	SUMMER	WINTER
MINIMUM BASE RATE CHARGE ($/DAY)	$0.10	$0.10	$0.10
TIER 1 ENERGY RATE b/	$0.07061	—	—
TIER 2 ENERGY RATE	$0.10750	—	—
ON-PEAK ENERGY RATE	—	$0.35480	—
MID-PEAK ENERGY RATE	—	$0.13687	$0.11118
OFF-PEAK ENERGY RATE	—	$0.07012	$0.07012
TOU-D BASELINE CREDIT c/	—	$0.03689	$0.03689
METER CHARGE ($/DAY)	—	$0.15	$0.15

a/ Time of use periods same as for TOU-GS and TOU-8. Schedule TOU-D to be implemented by June 1, 1988.

b/ The Tier 1 energy rate (Baseline) is 85% of the System Average Rate (SAR), where the SAR is total revenue requirement from sales divided by total sales ($5,351.454 MM / 64,529.2 MMKWH = 0.08293 $/KWH).

c/ TOU-D energy rates are reduced by baseline credit for an amount equal to their otherwise applicable baseline allowance, but no more than their actual kWh usage.

APPENDIX I
Page 2

SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED RESIDENTIAL RATES

SCHEDULE DM

Adopted Daily Baseline kWh Allowance.

Summer Season * Baseline Region	kWh Per Day Basic Allocation	kWh Per Day All-Electric Allocation
10	4.7	5.6
13	6.8	12.4
14	6.9	10.2
15	20.7	20.7
16	6.6	11.8
17	6.0	7.7

Winter Season ** Baseline Region	kWh Per Day Basic Allocation	kWh Per Day All-Electric Allocation
10	5.0	9.4
13	5.1	17.0
14	5.9	17.4
15	6.4	13.0
16	6.5	24.1
17	5.3	11.7

* Summer Season shown above for Baseline Regions 10, 13, 14, 16, and 17 is May 1, through October 31. Summer Season shown above for Baseline Region 15 is June 1, through September 30.

** Winter Season shown above for Baseline Regions 10, 13, 14, 16 and 17 is November 1, through April 30. Winter Season shown above for Baseline Region 15 is October 1, through May 31.

SCHEDULES DM, DMS-1, DMS-2

DM: Diversity factor of $.08/unit/day.

DMS-1: Discount of $.08/unit/day adjusted by diversity factor of $.08/unit/day.

DMS-2: Discount of $.26/unit/day adjusted by diversity factor of $.05/unit/day.

ADOPTED RESIDENTIAL RATES
DOMESTIC SEASONAL

SCHEDULE DS

APPLICABILITY

Applicable as an option to customers served under Schedule No. D, Domestic Service, whose average monthly consumption over the most recent 12 months exceeds 1,200 kWh, and who have established a minimum of 12 months billing history at their present account. This schedule is not applicable to customers receiving service under Schedule Nos. D-APS-2, DM, DMS-1, DMS-2, or TOU-D.

TERRITORY

Within the entire territory served.

RATES

The rate of the single family domestic rate schedule, Schedule No. D, shall apply except that the Customer's bill for the summer and winter season days shall be increased or decreased by the following adjustment:

	Per Meter Per Day
Adjustment:	
Summer Season Premium:	
The daily Summer Season kWh usage for the current billing period in excess of the Average Winter Season Daily usage *, per kWh	7.000¢
Winter Season Discount:	
The daily Winter Season kWh usage for the current billing period in excess of the Average Summer Season Daily usage *, per kWh	-7.000¢

* The kWh resulting from the above computation shall not exceed the Nonbaseline kWh daily usage for the Summer or Winter Season days during the billing period.

SPECIAL CONDITIONS

1. Seasons: The Summer Season shall commence on June 1 and continue through September 30 of each year. The Winter Season shall commence on December 1 and continue through March 31 of each year.

2. Average Daily Usage: The Average Summer Season Daily Usage is the average daily kWh consumption recorded during the preceding Summer Season. The Average Winter Season Daily usage is the average daily kWh consumption recorded during the preceding Winter Season.

3. Contract Provisions: Service under this schedule is available only on annual contract. The contract shall renew automatically unless the customer notifies the Company, otherwise, at least 30 days prior to its expiration, except that customers shall be removed from this schedule at the end of an annual contract year where average monthly consumption over the past 12 months is less than 1,000 kWh for 3 consecutive billing periods.

SCHEDULES DX

Experimental domestic schedules to be eliminated as of January 1, 1988.

APPENDIX I
PAGE 4
SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED SMALL AND MEDIUM POWER RATES

EFFECTIVE 01-01-88
($/KWH)

SCHEDULE	GS-SP/TP	TC-1	GS-2	
SEASON	ANNUAL	ANNUAL	SUMMER	WINTER
CUSTOMER CHARGE	$0.25/DAY	$0.25/DAY	$30/MONTH	$30/MONTH
DEMAND CHARGE ($/KW/MONTH) a/	--	--	$8.30	$2.60
TIER 1 ENERGY RATE (FIRST 300 KWH PER KW)	--	--	$0.07506	$0.07506
TIER 2 ENERGY RATE (EXCESS)	--	--	$0.05012	$0.05012
FLAT ENERGY RATE	$0.09579	$0.08304	--	--

SCHEDULE CHANGES:

1. GS-1 replaced by GS-SP (single phase) and GS-TP (three phase).

2. GS-TP: limited to existing GS-1 three phase customers at present and to be phased out by 12/31/90. Thereafter, these three phase customers will be assigned to GS-2, TOU-GS, PA-1 or PA-2 based on operational characteristics.

3. GS-PG: closed to new customers as of 01/01/88.

4. SCG-1,-2,-3 and S replaced by revised S or standby schedule. See pages 17-18 of this appendix.

a/ Unratcheted.

APPENDIX I
PAGE 5
SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED SMALL AND MEDIUM POWER TIME-OF-USE RATES

EFFECTIVE 01-01-88
($/KWH)

SCHEDULE	TOU-6S		TOU-6S-SOP		
SEASON	SUMMER	WINTER	SUMMER	SPRING/FALL	WINTER
CUSTOMER CHARGE	$30/MONTH	$30/MONTH	$30/MONTH	$30/MONTH	$30/MONTH
TIME RELATED DEMAND CHARGE ($/KW/MONTH):					
ON-PEAK	$11.30	--	$33.00	--	--
MID-PEAK	$1.75	--	$0.90	$0.45	$0.45
NON-TIME RELATED DEMAND CHARGE ($/KW/MONTH) a/	$2.60	$2.60	$2.60	$2.60	$2.60
ON-PEAK ENERGY RATE	$0.10402	--	$0.10329	--	--
MID-PEAK ENERGY RATE	$0.08419	$0.09458	$0.10329	$0.07835	$0.08529
OFF-PEAK ENERGY RATE	$0.05012	$0.05012	$0.06819	$0.07283	$0.07283
SUPER OFF-PEAK ENERGY RATE	--	--	$0.03512	$0.03512	$0.03512
METER CHARGE ($/MONTH)	$7.00	$7.00	$7.00	$7.00	$7.00

SCHEDULE CHANGES:

1. TOU-6S-SOP: new schedule for TOU-6S customers, providing fourth TOU period (i.e., midnight to 6 AM). See detail on TOU-6S-SOP and TOU-8-SOP periods, page 7 of this appendix.

a/ Unratcheted.

SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED SMALL AND MEDIUM POWER RATES

CHANGES TO SPECIAL CONDITIONS:
SCHEDULE GS-2

8. Voltage Discount: The monthly Summer Demand Charge of $8.30 per kW will be reduced by 3.1% for service delivered and metered at voltages of from 2 kV through 50 kV and by 7.2% for service delivered and metered at voltages over 50 kV. The Base Rate Energy Charges will be reduced by 5.3% for service delivered and metered at voltages of from 2 kV through 50 kV and by 11.8% for service delivered and metered at voltages over 50 kV.

SCHEDULE TOU-GS

1. Time periods are defined as follows:

On-Peak: Noon to 6:00 p.m. summer weekdays except holidays

Mid-Peak: 8:00 a.m. to Noon and 6:00 p.m. to 11:00 p.m. summer weekdays except holidays
8:00 a.m. to 9:00 p.m. winter weekdays except holidays

3. Maximum Demand: Maximum Demands shall be established for On-Peak, Mid-Peak, and Off-Peak Time periods. The maximum demand for each period shall be the measured maximum average kilowatt input, indicated or recorded by instruments to be supplied by the Company, during any 15-minute metered interval in the month. Where the demand is intermittent or subject to violent fluctuations, a 5-minute interval may be used.

4. Demand Charge: The Demand Charge shall include the following billing components. The Time Related Component shall be the kilowatts of Maximum Demand recorded during the monthly billing period for each of the On-Peak, Mid-Peak, and Off-Peak Time Periods. The Non-Time Related Component shall be the kilowatts of Maximum Demand recorded during the monthly billing period, except as provided in Special Condition No. 5 below. Separate Demand Charge(s) for the On-Peak, Mid-Peak, and Off-Peak time periods shall be established for each monthly billing period. The Demand Charge for each time period shall be based on the maximum demand for that time period occurring during the respective monthly billing period. The Maximum Demand shall be determined to the nearest kW.

5. Minimum Billing Demand: A Monthly Minimum Billing Demand shall be established and apply for the Non-Time Related Component of the Demand Charge when, in the Company's opinion, a customer's load creates demands which cannot be accurately measured by the Company's metering equipment. It shall be based on the lesser of (1) the nominal kilovolt-ampere-rating of the Company's serving transformer(s) or (2) the standard transformer size determined by the Company as required to serve the customer's kilowatt demand. However, if a montnly minimum billing demand was previously established for diversified resistance welder load, computed in accordance with the Section designated Welder Service in Rule No. 2, it shall apply until such time as the applicable transformer size, as stated above, is determined by the Company. The Minimum Billing Demand shall be billed in lieu of but at the same rate as the Non-Time Related Component of the Demand Charge.

8. Voltage Discount: The Time Related Component of the Demand Charge(s) will be reduced by 3.1% for service delivered and metered at voltages of from 2 kV through 50 kV and by 7.2% for service delivered and metered at voltages over 50 kV. The base rate energy charges will be reduced by 5.3% for service delivered and metered at voltages of from 2 kV through 50 kV and by 11.8% for service delivered and metered at voltages over 50 kV.

APPENDIX I

SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED TIME-OF-USE PERIODS
FOR SUPER OFF-PEAK RATES

SCHEDULES TOU-8-SOP AND TOU-6S-SOP:

	Summer	Spring/Fall	Winter
Months	July, August, September	April, May, June, October	November, December, January, February, March
On-Peak Hours	1 pm to 5 pm, Weekdays	——	——
Mid-Peak Hours	10 am to 1 pm, & 5 pm to 9 pm, Weekdays	9 am to 4 pm, Weekdays	8 am to 11 am, & 5 pm to 8 pm, Weekdays
Off-Peak Hours	6 am to 10 am, & 9 pm to 12 pm, Weekdays, and 6 am to 12 pm Weekends	6 am to 9 am, & 4 pm to 12 pm, Weekdays, and 6 am to 12 pm Weekends	6 am to 8 am, 11 am to 5 pm, & 8 pm to 12 pm, Weekdays, and 6 am to 12 pm Weekends
Super-Off-Peak Hours	12 pm to 6 am, Weekdays and Weekends	12 pm to 6 am, Weekdays and Weekends	12 pm to 6 am, Weekdays and Weekends

SCHEDULE TOU-PA-SOP:

	Summer	Winter
Months	July, August, September	October to June
On-Peak Hours	1 pm to 5 pm, Weekdays	——
Off-Peak Hours	6 am to 1 pm, & 5 pm to 12 pm, Weekdays, and 6 am to 12 pm Weekends	6 am to 12 pm Weekdays and Weekends
Super-Off-Peak Hours	12 pm to 6 am, Weekdays and Weekends	12 pm to 6 am, Weekdays and Weekends

APPENDIX I
PAGE 8
SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED LARGE POWER RATES

EFFECTIVE 01-01-88
($/KWH)

SCHEDULE	TOU-8			TOU-8-SOP		
VOLTAGE	SECONDARY	PRIMARY	SUBTRANS	SECONDARY	PRIMARY	SUBTRANS
CUSTOMER CHARGE	$250.00	$250.00	$250.00	$250.00	$250.00	$250.00
TIME RELATED DEMAND CHARGE ($/KW/MONTH)						
SUMMER ON-PEAK	$13.25	$13.00	$11.20	$33.00	$33.00	$31.50
SUMMER MID-PEAK	$2.05	$2.00	$1.75	$0.90	$0.90	$0.85
SPRING/FALL MID-PEAK	--	--	--	$0.45	$0.45	$0.45
WINTER MID-PEAK	--	--	--	$0.45	$0.45	$0.45
NON-TIME RELATED DEMAND CHARGE ($/KW/MONTH) a/	$2.70	$2.00	$0.25	$2.70	$2.00	$0.25
SUMMER ENERGY CHARGE:						
ON-PEAK	$0.09365	$0.08517	$0.06798	$0.09907	$0.09724	$0.07528
MID-PEAK	$0.07580	$0.06893	$0.05502	$0.09907	$0.09724	$0.07528
OFF-PEAK	$0.05012	$0.05012	$0.05012	$0.06538	$0.06443	$0.04989
SUPER OFF-PEAK	--	--	--	$0.03512	$0.03512	$0.03512
SPRING/FALL ENERGY CHARGE:						
ON-PEAK	--	--	--	--	--	--
MID-PEAK	--	--	--	$0.07513	$0.07404	$0.05733
OFF-PEAK	--	--	--	$0.06976	$0.06874	$0.05324
SUPER OFF-PEAK	--	--	--	$0.03512	$0.03512	$0.03512
WINTER ENERGY CHARGE:						
MID-PEAK	$0.08515	$0.07744	$0.06181	$0.08193	$0.08121	$0.06329
OFF-PEAK	$0.05012	$0.05012	$0.05012	$0.06976	$0.06874	$0.05324
SUPER OFF-PEAK	--	--	--	$0.03512	$0.03512	$0.03512
RATE LIMITER:						
AVERAGE SUMMER	$0.11344	$0.11344	--	--	--	--
SUMMER ON-PEAK	$0.67480	$0.66199	$0.53733	--	--	--

SCHEDULE CHANGES:

1. TOU-8 applicability change: Customers with demands in excess of 4,000 kw for 9 of the preceeding 12 months, who otherwise qualify, may elect interruptible service on Schedule No. I-5. Any customer whose monthly maximum demand has registered below 450 kw for 12 consecutive months is ineligible for service under this schedule.

2. Revised TOU periods: see TOU-8S for periods.

a/ Unratcheted

APPENDIX I
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SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED LARGE POWER RATES (CONTINUED)

EFFECTIVE 01-01-88
($/KWH)

SCHEDULE CHANGES (CONTINUED):

3. TOU-8 RATE LIMITERS:

A. Average summer rate limiter. For secondary and primary customers, the customer's total monthly bill under this schedule, excluding the Public Utilities Commission Reimbursement Fee, surcharges or facilities charges, shall be reduced if necessary, so that the average rate during a summer month does not exceed $0.11344 per kwh. This Special Condition is not applicable to customers taking service under Schedule S.

B. On-peak rate limiter. The customers total monthly bill under this schedule, excluding the Public Utilities Commission Reimbursement Fee, surcharges or facilities charges, shall be reduced if necessary, so that the average rate during the on-peak period in a summer month does not exceed $0.53733 per kwh for service metered and delivered at voltages exceeding 50 kv, $0.66199 per kwh for service metered and delivered at voltages from 2 kv through 50 kv and $0.67480 per kwh for service metered and delivered at voltages below 2 kv. This Special Condition is also applicable to customers taking service under Schedule S.

4. SCG-1,-2,-3 and S replaced by revised S or standby schedule.

5. I-1: continues to be closed; credit revised to reflect 4 (vs 12) month on peak period.

6. I-2: closed 1/1/88; credit revised to reflect 4 (vs 12) month on peak period.

7. I-3 and I-5: see discussion in decision, pp. 327-338.

8. I-4: eliminated (no customers).

9. I-6: new schedule.

10. Real Time Pricing Experimental Schedule RTP-2: Applicable to commercial and industrial customers eligible for service under Schedule TOU-8, General Service - Large. This schedule is limited to customers that have been selected by the Company to participate in a Real Time Pricing experimental program. This schedule is subject to meter availability. This schedule is also available to customers currently served under Schedule RTP, who desire to transfer to this schedule after they have successfully completed one or two years of service under Schedule RTP.

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SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED LARGE POWER INTERRUPTIBLE RATES

EFFECTIVE 01-01-88
($/KWH)

SCHEDULE	TOU-8-SOP-I-A			TOU-8-SOP-I-B		
VOLTAGE	SECONDARY	PRIMARY	SUBTRANS	SECONDARY	PRIMARY	SUBTRANS
CUSTOMER CHARGE	$250.00	$250.00	$250.00	$250.00	$250.00	$250.00
TIME RELATED DEMAND CHARGE ($/KW/MONTH)						
SUMMER ON-PEAK	$22.20	$22.20	$21.15	$23.50	$23.50	$22.50
SUMMER MID-PEAK	$0.55	$0.55	$0.55	$0.60	$0.60	$0.60
SPRING/FALL MID-PEAK	$0.30	$0.30	$0.30	$0.30	$0.30	$0.30
WINTER MID-PEAK	$0.30	$0.30	$0.30	$0.30	$0.30	$0.30
NON-TIME RELATED DEMAND CHARGE ($/KW/MONTH) a/	$2.70	$2.00	$0.25	$2.70	$2.00	$0.25
SUMMER ENERGY CHARGE:						
ON-PEAK	$0.09561	$0.09483	$0.07298	$0.09603	$0.09513	$0.07327
MID-PEAK	$0.09561	$0.09483	$0.07298	$0.09603	$0.09513	$0.07327
OFF-PEAK	$0.06226	$0.06235	$0.04790	$0.06264	$0.06261	$0.04815
SUPER OFF-PEAK	$0.03355	$0.03355	$0.03355	$0.03374	$0.03374	$0.03374
SPRING/FALL ENERGY CHARGE:						
ON-PEAK	—	—	—	—	—	—
MID-PEAK	$0.07293	$0.07191	$0.05529	$0.07320	$0.07217	$0.05534
OFF-PEAK	$0.06745	$0.06650	$0.05110	$0.06773	$0.06678	$0.05137
SUPER OFF-PEAK	$0.03355	$0.03355	$0.03355	$0.03374	$0.03374	$0.03374
WINTER ENERGY CHARGE:						
MID-PEAK	$0.07969	$0.07903	$0.06121	$0.07997	$0.07217	$0.06147
OFF-PEAK	$0.06754	$0.06659	$0.05118	$0.06781	$0.06685	$0.05144
SUPER OFF-PEAK	$0.03355	$0.03355	$0.03355	$0.03374	$0.03374	$0.03374

Note: The penalty provisions for TOU-8-SOP-I (A and B) are the same as those of I-6 (A and B) and are shown in schedule I-6 Special Condition No. 10 in this appendix.

a/ [illegible]

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SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED LARGE POWER INTERRUPTIBLE RATES

EFFECTIVE 01-01-88
($/KWH)

CHEDULE	I-5-A			I-5-B		
OLTAGE	SECONDARY	PRIMARY	SUBTRANS	SECONDARY	PRIMARY	SUBTRANS
USTOMER CHARGE	$250.00	$250.00	$250.00	$250.00	$250.00	$250.00
IME RELATED DEMAND CHARGE ($/KW/MONTH)						
SUMMER ON-PEAK	$13.25	$13.00	$11.20	$13.25	$13.00	$11.20
SUMMER MID-PEAK	$2.05	$2.00	$1.75	$2.05	$2.00	$1.75
ON-TIME RELATED DEMAND CHARGE ($/KW/MONTH) a/	$2.70	$2.00	$0.25	$2.70	$2.00	$0.25
UMMER ENERGY CHARGE:						
ON-PEAK	$0.07865	$0.07017	$0.05298	$0.09365	$0.08517	$0.06798
MID-PEAK	$0.06080	$0.05393	$0.04002	$0.07580	$0.06893	$0.05502
OFF-PEAK (TIER 1)	$0.02512	$0.02512	$0.02512	$0.05012	$0.05012	$0.05012
OFF-PEAK (TIER 2)	--	--	--	$0.02512	$0.02512	$0.02512
INTER ENERGY CHARGE:						
MID-PEAK	$0.07015	$0.06244	$0.04681	$0.08515	$0.07744	$0.06181
OFF-PEAK (TIER 1) b/	$0.02512	$0.02512	$0.02512	$0.05012	$0.05012	$0.05012
OFF-PEAK (TIER 2) b/	--	--	--	$0.02512	$0.02512	$0.02512

EDULE CHANGES:		Present Credit ($/kw/mo)	Adopted Credit c/ ($/kw/SUMMER mo)
-1:	Rate A	$3.00	$8.10
	Rate B	$2.50	$6.70
-2:	Rate A	$3.10	$8.30
	Rate B	$2.60	$6.90
-3:	Rate A (Energy Credit)	$2.50	NO CHANGE
	Rate B	$2.00	$5.30
	Rate C	$1.50	$4.00
	Rate D	$1.00	$2.70
-5:	Rate A (Energy Credit)		NO CHANGE
	Rate B (Energy Credit)		NO CHANGE

e: I-5A rates equal TOU-8 rates minus 1.5 c/kwh for on-peak and mid-peak energy, and minus 2.5 c/kwh for off-peak energy.

I-5B rates equal TOU-8 rates, except off-peak kwh beyond 300 kwh/kw of the Firm Service Level equal TOU-8 off-peak energy rates minus 2.5 c/kwh.

a/ Unratcheted.
b/ See pp. 337-338 of decision for note on off-peak rate floor.
c/ Developed by multiplying present credit by ratio of total TOU-8 on-peak kw to summer TOU-8 on-peak kw.

APPENDIX I
PAGE 12
SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED LARGE POWER INTERRUPTIBLE RATES

EFFECTIVE 01-01-88
($/KWH)

SCHEDULE		I-6 A			I-6 B	
VOLTAGE	SECONDARY	PRIMARY	SUBTRANS	SECONDARY	PRIMARY	SUBTRANS
CUSTOMER CHARGE	$250.00	$250.00	$250.00	$250.00	$250.00	$250.00
TIME RELATED DEMAND CHARGE ($/KW/MONTH)						
SUMMER ON-PEAK	$8.69	$8.58	$6.97	$9.25	$9.13	$7.49
SUMMER MID-PEAK	$1.34	$1.31	$1.09	$1.43	$1.40	$1.17
SPRING/FALL MID-PEAK	--	--	--	--	--	--
WINTER MID-PEAK	--	--	--	--	--	--
NON-TIME RELATED DEMAND CHARGE ($/KW/MONTH) a/	$2.70	$2.00	$0.25	$2.70	$2.00	$0.25
SUMMER ENERGY CHARGE:						
ON-PEAK	$0.08667	$0.07834	$0.06171	$0.08754	$0.07919	$0.06249
MID-PEAK	$0.07040	$0.06363	$0.05021	$0.07107	$0.06429	$0.05080
OFF-PEAK	$0.04554	$0.04554	$0.04554	$0.04611	$0.04611	$0.04611
SUPER OFF-PEAK	--	--	--	--	--	--
WINTER ENERGY CHARGE:						
MID-PEAK	$0.07952	$0.07207	$0.05686	$0.08022	$0.07274	$0.05747
OFF-PEAK	$0.04538	$0.04538	$0.04538	$0.04597	$0.04597	$0.04597
SUPER OFF-PEAK	--	--	--	--	--	--

a/ Unratcheted.

SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED INTERRUPTIBLE RATES

Schedule No. I-6-A
TIME-OF-USE
RAL SERVICE - LARGE - INTERRUPTIBLE
TEN-MINUTE NOTIFICATION

SPECIAL CONDITIONS

1. Voltage: Service will be supplied at one standard voltage.

2. Maximum Demand: Maximum demands shall be established for the On-Peak, Mid-Peak, and Off-Peak Time Periods. The maximum demand for each period shall be the measured maximum average kilowatt input indicated or recorded by instruments to be supplied by the Company, during any 15-minute metered interval in the month. Where the demand is intermittent or subject to violent fluctuations, a 5-minute interval may be used.

3. Interruptible Load: The Interruptible Load is the estimated increment of the customer's Maximum Demand that normally occurs above the Firm Service Level and, under normal operating conditions, would be the amount of load to be disconnected from the Company's lines within the specified time period following Notice of Interruption.

4. Firm Service Level: Firm Service Level is the Maximum Demand the Company is expected to supply during any Period of Interruption. The Firm Service level shall be specified by the customer. Increases in Firm Service Level may be made no more often than once per year and only when the customer has made a bona fide addition of load. Such changes in Firm Service Level are subject to the approval of the Company. Customers served under this schedule shall establish a Firm Service Level of zero or greater.

5. Interruptible Demand and Energy: Interruptible Demand is all kW of Maximum Demand in excess of the Firm Service Level. Interruptible Energy is the number of kWh in each Time Period which exceeds the product of the Firm Service Level kW multiplied by the total number of hours in the Time Period.

6. Notice of Interruption: Notice of Interruption can be given under this schedule when, in the Company's judgment, a shortage of supply exists. The Company shall notify the customer to reduce the Maximum Demand imposed on the Company to the Firm Service Level. Upon receipt by a customer of a Notice of Interruption, the customer shall reduce the Maximum Demand imposed on the Company to the Firm Service Level within 10 minutes.

7. Period of Interruption: A Period of Interruption is a time interval which commences immediately after Notice of Interruption and which ends upon notification by the Company of the end of Period of Interruption.

8. Excess Demand: The Maximum Demand occurring during each Period of Interruption which is in excess of Firm Service shall be considered Excess Demand.

9. Excess Energy: The number of kWh consumed in each Time Period involved in a Period of Interruption which exceeds the product of the Firm Service Level kW multiplied by the total number of hours of Interruption within the Time Period, shall be considered Excess Energy.

10. Charges for Excess Demand and Energy: Language for Special Condition 10 follows I-6-B.

11. Ownership and Control of Facilities: Communication, metering, and interrupting facilities, as specified by the Company, will be installed, owned, and maintained in accordance with Company specifications at customer's expense, including such facilities not located on the customer's property. These facilities will be solely under operational control of the Company unless otherwise specified by the Company.

Such communications and interrupting facilities may include, but will not be limited to, the following:

a. Necessary facilities between the customer and the Company to provide Notice of Interruption.

b. Equipment to permit remote monitoring of the customer's load.

SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED INTERRUPTIBLE RATES

I.6-A (Cont'd.)

INTERRUPTIBLE -
TEN-MINUTE NOTIFICATION

12. Contracts: A contract is required for service under this schedule. During the initial year of service the customer may terminate service under this schedule upon not less than 30 days written notice to the company. After the initial year not less than five years written notice to modify or terminate service under this schedule will be required. A customer may not obtain interruptible service within three years following termination of interruptible service under this schedule. Customers permitted by the Company to change to this schedule from another interruptible rate schedule shall, without further action by the Company, retain the termination requirements, if any, of the prior schedule and any contract associated therewith.

13. Number and Duration of Interruption: The number of Periods of Interruption will not exceed 25 times per calendar year. The duration of the Periods of Interruption will not exceed 300 hours per calendar year.

14. Interconnection: Service under this schedule may, upon approval by the Company, include electric service supplied by a cogeneration or small power production source to a single customer on the same premises as provided in the terms and conditions of a contract.

SCHEDULE NO. 1-6-B

INTERRUPTIBLE -
ONE-HOUR NOTIFICATION

Special Conditions for I-6-B are the same as for I-6-A, except for the following:

6. Notice of Interruption: Notice of Interruption can be given under this schedule when, in the Company's judgment, a shortage of supply exists. The Company shall notify the customer to reduce the Maximum Demand imposed on the Company to the Firm Service Level. Upon receipt by a customer of a Notice of Interruption, the customer shall reduce the Maximum Demand imposed on the Company to the Firm Service Level within one hour.

7. Period of Interruption: A Period of Interruption is a time interval which commences one hour after Notice of Interruption and which ends upon notification by the Company of the end of Period of Interruption.

10. Charges for Excess Demand and Energy: See following page for Special Condition 10.

SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED INTERRUPTIBLE RATES

SPECIAL CONDITION NO. 10

SCHEDULE I-6-A

Charges for Excess Demand and Energy:

For each period of interruption during which the customer fails to interrupt and hence incurs Excess Demand and therefore Excess Energy, Excess Demand shall be multiplied by the applicable $/kW penalty as shown below and the Excess Energy shall be multiplied by the applicable $/kWh penalty as shown below and both products shall be added to the customer's billing as otherwise provided in this schedule.

	Applicable Penalties					
	Service Voltage in Excess of 50 kV		Service Voltage = 2 kV - 50 kV		Service Voltage Below 2 kV	
	$/kW	¢/kWh	$/kW	¢/kWh	$/kW	¢/kWh
First Failure	3.26	13.932	3.41	14.508	3.52	14.958
Second Failure	6.53	27.863	6.82	29.016	7.03	29.916
3rd & Subsequent Failures	9.79	41.795	10.22	43.524	10.55	44.874

Second, third and subsequent failures are defined as periods of interruption during which the customer incurs Excess Demand within twelve months of the first failure to interrupt.

After twelve consecutive months of service on this schedule without recorded Excess Demand or Energy the charge for Excess Demand and Excess Energy will recycle to the charges for the first failure to interrupt.

SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED INTERRUPTIBLE RATES

SPECIAL CONDITION NO. 10

SCHEDULE I-6-B

Charges for Excess Demand and Energy:

For each period of interruption during which the customer fails to interrupt and hence incurs Excess Demand and therefore Excess Energy, Excess Demand shall be multiplied by the applicable $/kW penalty as shown below and the Excess Energy shall be multiplied by the applicable $/kWh penalty as shown below and both products shall be added to the customer's billing as otherwise provided in this schedule.

	Applicable Penalties					
	Service Voltage in Excess of 50 kV		Service Voltage = 2 kV - 50 kV		Service Voltage Below 2 kV	
	$/kW	¢/kWh	$/kW	¢/kWh	$/kW	¢/kWh
First Failure	2.86	12.204	2.98	12.709	3.08	13.103
Second Failure	5.72	24.408	5.97	25.417	6.16	26.206
3rd & Subsequent Failures	8.57	36.611	8.95	38.126	9.24	39.309

Second, third and subsequent failures are defined as periods of interruption during which the customer incurs Excess Demand within twelve months of the first failure to interrupt.

After twelve consecutive months of service on this schedule without recorded Excess Demand or Energy the charge for Excess Demand and Excess Energy will recycle to the charges for the first failure to interrupt.

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SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED STANDBY RATES

SCHEDULE S

APPLICABILITY

Applicable to customers taking service under a regular service rate schedule and where a part or all of the electrical requirements of the customer can be supplied from a cogeneration or small power production source which meets the criteria for Qualifying Facility as defined under 18 CFR, Chapter 1, part 292, subpart B of the Federal Energy Regulatory Commission (FERC) regulations. The cogeneration or small power production source may be connected for: (1) parallel operation with the service of the Company; or (2) isolated operation with standby or breakdown service provided by the Company by means of a double-throw switch. This schedule is also applicable to standby or breakdown service where the entire electrical requirements on the customer's premises are not regularly supplied by the Company and the generation serving the customer is (1) not a Qualifying Facility, and (2) not in parallel with the service of the Company.

TERRITORY

Within the entire territory served.

RATES

Standby Charge:	Service Voltage	Per Meter Per Month
All kW of standby demand, per kW	Below 2 kV	$2.70
All kW of standby demand, per kW	2 kV to 50 kV	$2.00
All kW of standby demand, per kW	Above 50 kV	$0.25

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

The demand charge on Schedule Nos. CS-2 or PA-2, or the Non-Time Related Demand Charges designated in the normally applicable regular service rate schedule, shall be applied to all kW of Maximum Demand in the current month less Standby Demand.

All other charges including Minimum Billing Demand charges and provisions of the applicable regular service rate schedule designated in the Generation Agreement or the Contract for Electric Service shall apply.

SPECIAL CONDITIONS

1. Contract: A Contract is required for service under this schedule.

2. Generation Agreement: A Generation Agreement with the customer shall be required for service under this schedule where the cogeneration or small power production source is connected for parallel operation with the service of the Company.

3. Standby Demand: The level of standby demand shall be set forth in the Generation Agreement or Contract for Electric Service. The level of standby demand shall be determined by the Company and shall be the lower of (a) the nameplate capacity of the customer's generating facility; or (b) the Company's estimate of the customer's peak demand.

The Company reserves the right to install, at the customer's expense, a demand meter to measure the customer's demand. The highest recorded demand shall be used to determine the customer's level of standby demand.

SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED STANDBY RATES

SCHEDULE S (Cont'd.) (Continued)

SPECIAL CONDITIONS (Continued)

4. Allowance for Maintenance: After a customer has received service under this schedule for a period of six months, the added demand created by scheduled maintenance outages of the generating facility will be ignored for purposes of determining the first block demand on Schedule Nos. CS-2 or PA-2, or the Time Related Component of the demand charges under the applicable regular service rate schedule, in months acceptable to the Company upon advance notice and subject to prevailing system peak conditions, subject to the conditions stated herein. Such conditions are that customer schedule and perform maintenance in accordance with the advance notice, outage duration, and outage frequency requirements set forth in the Generation Agreement, and following the period of scheduled maintenance, customer shows, to the satisfaction of the Company, what part of the recorded maximum demand utilized for billing in any of the months was added demand due to outage for such scheduled maintenance. This condition is applicable for one continuous outage per year of up to 30 consecutive days.

The Company may, at its option, require that the customer defer scheduled maintenance. If scheduled maintenance is deferred, the Company will allow an outage for maintenance at a later date with allowance for maintenance in accordance herewith. Notice of such deferral, if required, shall be provided to the customer not less than 60 days prior to customer's scheduled outage date, except in the event of emergency. The Allowance for Maintenance applies only to customers served on Schedule Nos. CS-2, PA-2, or a rate schedule which has a Time Related Component within the demand charge.

5. Excess Energy: For parallel connections, the customer may sell power to the Company under the terms of the Generation Agreement.

6. On-peak Rate Limiter: The monthly bill under the customer's regular schedule, excluding the Public Utilities Commission Reimbursement Fee, surcharges or facilities charges, shall be reduced if necessary, so that the average rate during the on-peak period in a summer month does not exceed 52.051 cents per kWh for service metered and delivered at voltages exceeding 50 kV, 64.127 cents per kWh for service metered and delivered at voltages from 2 kV thru 50 kV and 65.367 cents per kWh for service metered and delivered at voltages below 2kV.

SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED REAL TIME PRICING RATES

SCHEDULE RTP
DAILY PRICE SCENARIOS

SUMMER WEEKDAYS

Hour Ending @:	Extremely Hot Summer Weekday	Very Hot Summer Weekday	Hot Summer Weekday	Summer Weekday
Frequency:	6 days	9 days	13 days	69 days
1 AM	$.03966/kWh	$.03913/kWh	$.03833/kWh	$.03808/kWh
2	.03908	.03867	.03798	.03793
3	.03863	.03832	.03789	.03801
4	.03851	.03827	.03778	.03793
5	.03850	.03830	.03778	.03791
6	.03951	.03912	.03824	.03851
7	.05156	.05112	.05383	.05116
8	.05221	.05200	.05436	.05214
9	.05444	.05431	.05504	.05462
10	.06031	.05845	.05779	.05741
11	.33530	.11393	.06881	.06324
12 Noon	.66650	.14914	.07407	.05833
1 PM	1.02516	.23940	.09712	.06347
2	1.78198	.76842	.20069	.08722
3	2.70000	1.11025	.35410	.09479
4	1.91956	.97893	.18222	.07551
5	1.53898	.48523	.08804	.05542
6	1.20882	.20627	.06216	.05343
7	.97268	.19810	.07409	.05607
8	1.13071	.22476	.07147	.05595
9	.16306	.08310	.05512	.05569
10	.05336	.05320	.05559	.05246
11	.05239	.05199	.05429	.05201
12 Midnight	.05158	.05095	.05265	.05096

SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED REAL TIME PRICING RATES

SCHEDULE RTP
DAILY PRICE SCENARIOS

NON-SUMMER WEEKDAYS

Hour Ending @:	Spring/Fall Weekday	High Cost Winter Weekday	Winter Weekday
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Frequency:	54 days	18 days	83 days
1 AM	$.03893/kWh	$.03875/kWh	$.03931/kWh
2	.03871	.03866	.03916
3	.03867	.03854	.03910
4	.03860	.03854	.03910
5	.03858	.03870	.03922
6	.03892	.04015	.04049
7	.06165	.05129	.05595
8	.06408	.06147	.06513
9	.06270	.08675	.06958
10	.07528	.11669	.07384
11	.08847	.10413	.07656
12 Noon	.07627	.07195	.06348
1 PM	.07418	.06459	.06275
2	.08203	.06155	.06387
3	.07863	.05599	.05962
4	.06291	.05402	.05700
5	.05921	.05982	.06651
6	.05623	.08977	.07698
7	.05492	.18081	.08520
8	.05448	.08507	.06860
9	.05582	.05852	.06191
10	.06589	.05412	.05986
11	.05952	.05513	.06046
12 Midnight	.05399	.05425	.05676

SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED REAL TIME PRICING RATES

SCHEDULE RTP
DAILY PRICE SCENARIOS

WEEKENDS

Hour Ending @:	Weekend	High Cost Weekend
Frequency:	66 days	47 days
1 AM	$.03839/kWh	$.03930/kWh
2	.03833	.03913
3	.03819	.03908
4	.03816	.03908
5	.03810	.03910
6	.03816	.03942
7	.04933	.05598
8	.04991	.05635
9	.05167	.05628
10	.05215	.05608
11	.05198	.05502
12 Noon	.05200	.05330
1 PM	.05177	.05280
2	.05177	.05652
3	.05182	.05737
4	.05208	.05715
5	.05223	.05840
6	.05229	.06174
7	.05244	.06057
8	.05259	.05749
9	.05254	.05748
10	.05170	.05510
11	.05111	.05299
12 Midnight	.04917	.05092

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SOUTHERN CALIFORNIA EDISON COMPANY

ADOPTED LARGE POWER RATES

Schedule No. TOU-8-CR-1

GENERAL SERVICE - LARGE CONTRACT RATE 1

INCREMENTAL SALES

APPLICABILITY

Applicable to general service, including lighting and power, for any customer whose demand has exceeded 500 kW in at least three of the past 12 months, and for whom recorded demands are available for the past 12 months.

TERRITORY

Within the entire territory served.

RATES

Specific formulas and procedures for calculating the applicable monthly and annual Fixed Charge, Energy Charge, and Demand Charge shall be set forth in a Standard Contract Form on file with and approved by the Commission.

The following charges shall apply:

Fixed Charge: The Fixed Charge set forth in the Standard Contract Form shall be the difference between estimated annual revenue under Schedule No. TOU-8, or any rate option under which the customer is provided service, and estimated annual revenue under the Demand Charges and Energy Charges provided for in this Schedule. The Fixed Charge is calculated using Base Period energy and demand billing determinants and is adjusted annually for forecast inflation from the Base Period. Base Period energy and demand billing determinants shall be defined by the Company using 12 representative months of recorded consumption; this 12 months' consumption shall be derived from the customer's recorded consumption for the past 24 months.

Demand Charge: The Demand Charge set forth in the Standard Contract Form shall be the Posted Avoided Cost Capacity Prices in dollars per kW/month, including line loss adjustments by time-of-day and season, plus $1.00 per summer on-peak kW per month for Contribution to Fixed Costs.

Energy Charge: The Energy Charge set forth in the Standard Contract Form shall be the Posted Quarterly Avoided Cost Energy Prices in cents per kWh, including line loss adjustments, plus 2.0 cents per kWh for Contribution to Fixed Costs.

Added Facilities Charge: Any facilities required to be installed which, in the opinion of the Company, are to accommodate expanded electric service provided under this rate schedule shall be Added Facilities. Charges, terms, and conditions for such added facilities shall be in accordance with Rule No. 2.H.

SPECIAL CONDITIONS

1. Contract: A five-year contract is required for service under this Schedule. Service will not be provided on this schedule in excess of five years unless mutually agreed upon by both Edison and the customer. In addition, any contract for service under this schedule will not become effective until the contract has been approved by the Commission.

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SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED AGRICULTURAL RATES

RATE SCHEDULE	CUSTOMER CHARGE ($/MONTH)	METER CHARGE ($/MONTH)	DEMAND CHARGE ($/KW OR HP) SUMMER	DEMAND CHARGE ($/KW OR HP) WINTER	ENERGY CHARGE ($/KWH) TIER 1	ENERGY CHARGE ($/KWH) TIER 2
PA-2	$20.00	—	$7.15	$1.15	0.08298	0.05012
					SUMMER	WINTER
PA-1	$10.00	—	$1.00	$1.00	0.07924	0.07924
TOU-PA-1	$10.00	—	$2.75	$2.75	—	—
ON-PEAK	—	—	—	—	0.08859	—
OFF-PEAK	—	—	—	—	0.05463	0.06765
TOU-ALMP-1	$10.00	—	—	—	—	—
			$21.00	$21.00		
ON-PEAK	—	—	$3.50 a/	$3.50	0.13023	—
OFF-PEAK	—	—	—	—	0.59972	0.06454
TOU-ALMP-2	$10.00	—	—	—	—	—
ON-PEAK	—	—	—	—	0.20896	—
OFF-PEAK	—	—	—	—	0.06710	0.07956
TOU-PA (<35 KW)	$30.00	$6.00	—	—	—	—
ON-PEAK	—	—	—	—	0.11704	—
MID-PEAK	—	—	—	—	0.09472	0.10641
OFF-PEAK	—	—	—	—	0.05012	0.05012
CONNECTED HP	—	—	$1.00	$1.00	—	—
TOU-PA-3 (<35 KW) -SPLIT WEEK	$30.00	$6.00	—	—	—	—
ON-PEAK	—	—	—	—	0.13396	—
MID-PEAK	—	—	—	—	0.10841	0.12179
OFF-PEAK	—	—	—	—	0.05012	0.05012
CONNECTED HP	—	—	$1.00	$1.00	—	—
TOU-PA-4 (<35 KW) -REDUCED PEAK HOUR	$30.00	$6.00	—	—	—	—
ON-PEAK	—	—	—	—	0.11902	—
MID-PEAK	—	—	—	—	0.09632	0.10821
OFF-PEAK	—	—	—	—	0.05012	0.05012
CONNECTED HP	—	—	$1.00	$1.00	—	—

a/ A charge of $21.00 is applied to the first 6 kw or less of on-peak billing demand. All excess kw of on-peak billing demand is assessed a charge of $3.50 per kw.

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SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED AGRICULTURAL RATES

RATE SCHEDULE	CUSTOMER CHARGE ($/MONTH)	METER CHARGE ($/MONTH)	DEMAND CHARGE ($/KW OR HP) SUMMER	WINTER	ENERGY CHARGE ($/KWH) SUMMER	WINTER
TOU-PA (>35 KW)	$30.00	$6.00	--	--	--	--
ON-PEAK	--	--	$6.00	--	0.10760	--
MID-PEAK	--	--	--	--	0.08708	0.09783
OFF-PEAK	--	--	--	--	0.05012	0.05012
NON-TIME RELATED DEMAND CHARGE	--	--	$1.15	$1.15	--	--
TOU-PA-3 (>35 KW) -SPLIT WEEK	$30.00	$6.00	--	--	--	--
ON-PEAK	--	--	$6.00	--	0.12031	--
MID-PEAK	--	--	--	--	0.09736	0.10938
OFF-PEAK	--	--	--	--	0.05012	0.05012
NON-TIME RELATED DEMAND	--	--	$1.15	$1.15	--	--
TOU-PA-4 (>35 KW) -REDUCED PEAK HOUR	$30.00	$6.00	--	--	--	--
ON-PEAK	--	--	$6.00	--	0.11936	--
MID-PEAK	--	--	--	--	0.08851	0.09943
OFF-PEAK	--	--	--	--	0.05012	0.05012
NON-TIME RELATED DEMAND CHARGE	--	--	$1.15	$1.15	--	--
TOU-PA-5 (>35 KW) -MINIMUM BILL b/	$30.00	$6.00	--	--	--	--
ON-PEAK	--	--	$6.00	--	0.11231	--
MID-PEAK	--	--	--	--	0.09089	0.10211
OFF-PEAK	--	--	--	--	0.05012	0.05012
NON-TIME RELATED DEMAND CHARGE	--	--	$1.15	$1.15	--	--
TOU-PA-SOP -SUPER OFF-PEAK	$30.00	$6.00	--	--	--	--
ON-PEAK	--	--	$33.00	--	0.08219	--
OFF-PEAK	--	--	--	--	0.05969	0.06140
SUPER OFF-PEAK	--	--	--	--	0.03512	0.03512
NON-TIME RELATED DEMAND CHARGE	--	--	$1.15	$1.15	--	--

CHANGES TO SPECIAL CONDITIONS:

PA-1:

5. Off-Peak Credit: The monthly service charge will be reduced by an off-peak credit of $0.50 per horsepower of connected load. Customers must agree to permit the Company to install, at customer expense, an automatic utility-controlled load disconnecting device designed to prevent the service from being energized during the summer on-peak hours of 12:00 - 6:00 PM, Monday through Friday. Service under this provision will be required for a minimum of one year.

b/ Minimum bill of $500.00 per month

SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED AGRICULTURAL RATES

CHANGES TO SPECIAL CONDITIONS (CONTINUED):

PA-2:

Add Special Condition as follows:

Off-Peak Credit: The non-coincident demand or minimum demand charge will be reduced by an off-peak credit of $0.50 per kw. Customers must agree to permit the Company to install, at customer expense, an automatic utility-controlled load disconnecting device designed to prevent the service from being energized during the summer on-peak hours of 12:00 - 6:00 PM, Monday through Friday. Service under this provision will be required for a minimum of one year.

SCHEDULE CHANGES:

1. PA-1 and all connected load schedules where Rate A is applicable: This schedule is applicable to accounts having a total connected load of less than 35 hp.
2. PA-2 and all demand metered schedules where Rate B is applicable: This schedule is applicable to accounts having 35 hp or more of total connected load or 35 Kw or more of maximun demand. This schedule is subject to meter availability.
3. NEW SCHEDULES:
   A. TOU-PA: Rate A - connected load, Rate B - demand metered.
   B. TOU-PA-3 (3 Day On-Peak Rate): Rate A - connected load, Rate B - demand metered.
   C. TOU-PA-4 (Reduced On-Peak Hours Rate): Rate A - connected load, Rate B - demand metered.
   D. TOU-PA-5 (Minimum Bill Rate): demand metered.
   E. TOU-PA-SOP (Super Off-Peak Rate): demand metered (See page 7 of this appendix for TOU-PA-SOP time-of-use periods).
4. PA-1-PG: closed January 1, 1988.
5. TOU-PA-1: closed January 1, 1985.
6. TOU-ALMP-1: to be superseded by TOU-PA.
7. TOU-ALMP-2: closed January 1, 1988.
8. OTHER SCHEDULES:
   A. AP-1: (Agricultural and Pumping - Interruptible) was established by Advice Letter 767-E, effective 10/28/87. See applicability and rate credit below.

APPLICABILITY:

Applicable to customers with a measured demand of 50 kw or greater, with a connected load of 50 horsepower or greater who are served under an Agricultural and Pumping rate schedule, and who elect to provide interruptible load automatically. However, this schedule is not applicable to customers receiving the Off-Peak Credit provided by Special Condition No. 5 of Schedule PA-1 or comparable special condition of Schedule PA-2, or to customers served under parallel generation or experimental rate schedules. Service under this schedule is subject to the availability of a control device and may not be available in certain areas of Edison's service territory where communication signaling equipment has not been installed or signal strength is inadequate to activate or deactivate interruption.

RATES:

The net billing amount determined under the applicable, regular rate schedule will be credited $0.015 per kwh per month.

SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED AGRICULTURAL RATES

ADOPTED TIME-OF-USE PERIODS

Schedule No. TOU-PA

Time periods are defined as follows:

On-Peak: Noon to 6:00 p.m. summer weekdays except holidays

Mid-Peak: 8:00 a.m. to noon and 6:00 p.m. to 11:00 p.m. summer weekdays except holidays
8:00 a.m. to 9:00 p.m. winter weekdays except holidays

Off-Peak: All other hours.

Holidays are New Year's Day (January 1), Washington's Birthday (third Monday in February), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Veterans Day (November 11), Thanksgiving Day (fourth Thursday in November), and Christmas (December 25).

When any holiday listed above falls on Sunday, the following Monday will be recognized as an off-peak period. No change will be made for holidays falling on Saturday.

The summer season shall commence at 12:00 a.m. on the first Sunday in June and continue until 12:00 a.m. of the first Sunday in October of each year. The winter season shall commence at 12:00 a.m. on the first Sunday in October of each year and continue until 12:00 a.m. of the first Sunday in June of the following year.

Schedule No. TOU-PA-3

Under this schedule the Customer shall select, on a one-time basis, one of the following Summer On-Peak weekday options:

Option 1: Monday, Tuesday, and Wednesday are On-Peak weekdays;

Option 2: Wednesday, Thursday, and Friday are On-Peak weekdays.

The Company, in order to maintain a balance between the number of customers on Option 1 or Option 2, may temporarily close either Option to new customers.

The Time Periods are defined as follows:

Option 1:

On-Peak: Monday, Tuesday, Wednesday, Noon to 6:00 p.m. summer weekdays, except holidays.

Mid-Peak: Thursday and Friday, Noon to 6:00 p.m. summer weekdays, except holidays and 8:00 a.m. to Noon and 6:00 p.m. to 11:00 p.m. summer weekdays, except holidlays;
8:00 a.m. to 9:00 p.m. winter weekdays, except holidays.

Off-Peak: All other hours.

Option 2:

On-Peak: Wednesday, Thursday, Friday, Noon to 6:00 p.m. summer weekdays, except holidays.

Mid-Peak: Monday and Tuesday, Noon to 6:00 p.m. summer weekdays, except holidays and 8:00 a.m. to Noon and 6:00 p.m. to 11:00 p.m. summer weekdays, except holidays; 8:00 a.m. to 9:00 p.m. winter weekdays, except holidays.

Off-Peak: All other hours.

Holidays are New Year's Day (January 1), Washington's Birthday (third Monday in February), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Veterans Day (November 11), Thanksgiving Day (fourth Thursday in November), and Christmas (December 25).

When any holiday listed above falls on Sunday, the following Monday will be recognized as an off-peak period. No change will be made for holidays falling on Saturday.

The summer season shall commence at 12:00 a.m. on the first Sunday in June and continue until 12:00 a.m. of the first Sunday in October of each year. The winter season shall commence at 12:00 a.m. on the first Sunday in October of each year and continue until 12:00 a.m. of the first Sunday in June of the following year.

SOUTHERN CALIFORNIA EDISON COMPANY.
ADOPTED AGRICULTURAL RATES

ADOPTED TIME-OF-USE PERIODS

Schedule No. TOU-PA-4

Under this schedule the Customer shall select, on a one-time basis, one of the following options for Summer On-Peak hours:

Option 1: Noon to 4:00 p.m.

Option 2: 1:00 p.m. to 5:00 p.m.

Option 3: 2:00 p.m. to 6:00 p.m.

The Time Periods are defined as follows:

Option 1:

On-Peak: Noon to 4:00 p.m. summer weekdays, except holidays.

Mid-Peak: 8:00 a.m. to Noon and 4:00 p.m. to 11:00 p.m. summer weekdays, except holidays and
8:00 a.m. to 9:00 p.m. winter weekdays, except holidays.

Off-Peak: All other hours.

Option 2:

On-Peak: 1:00 p.m. to 5:00 p.m. summer weekdays, except holidays.

Mid-Peak: 8:00 a.m. to 1:00 p.m. and 5:00 p.m. to 11:00 p.m. summer weekdays, except holidays, and
8:00 a.m. to 9:00 p.m. winter weekdays, except holidays;

Off-Peak: All other hours.

Option 3:

On-Peak: 2:00 p.m. to 6:00 p.m. summer weekdays, except holidays.

Mid-Peak: 8:00 a.m. to 2:00 p.m. and 6:00 p.m. to 11:00 p.m. summer weekdays, except holidays, and 8:00 a.m. to 9:00 p.m. winter weekdays, except holidays;

Off-Peak: All other hours.

Holidays are New Year's Day (January 1), Washington's Birthday (third Monday in February), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Veterans Day (November 11), Thanksgiving Day (fourth Thursday in November), and Christmas (December 25).

When any holiday listed above falls on Sunday, the following Monday will be recognized as an off-peak period. No change will be made for holidays falling on Saturday.

The summer season shall commence at 12:00 a.m. on the first Sunday in June and continue until 12:00 a.m. of the first Sunday in October of each year. The winter season shall commence at 12:00 a.m. on the first Sunday in October of each year and continue until 12:00 a.m. of the first Sunday in June of the following year.

Schedule No. TOU-PA-5

Same time-of-use periods as TOU-PA.

Schedule No. TOU-PA-SOP

See page 7 of this Appendix for TOU periods.

<u>MINIMUM DEMAND CHARGE</u> (For TOU-PA, TOU-PA-3, TOU-PA-4, TOU-PA-5, and TOU-PA-SOP)

Minimum Demand Charge: Where a contract demand is established, the monthly minimum demand charge shall be $1.00 per kilowatt of contract demand.

SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED STREET LIGHTING RATES

CHANGES TO SPECIAL CONDITIONS

SCHEDULE LS-2:

1. SCE proposed Special Condition 2 as amended by this decision:

   2a. The point or points of service connection shall be mutually agreed upon by the Company and the customer.

   b. Distribution line extensions to reach a street light or a street light system shall be in accordance with the applicable Rule No. 15, 15.1, or 15.2.

2. SCE proposed Special Condition 10 as amended by this decision is reflected on the following page.

3. SCE proposed Special Condition 12 (reflecting existing Special Condition 10) as amended by this decision:

   12. The total monthly kWh usage for each type of service shall be computed applying the following kWh per kW billing factors to the applicable lamp load wattage rating. The kWh shall be computed to the nearest watthour.

	kWh Per kW of Lamp Load			
	Incandescent	Mercury Vapor	High Pressure Sodium Vapor	Low Pressure Sodium Vapor
Type of Service:				
All Night				
Multiple Service	345.0	345.0	345.0	345.0
Series Service	393.7	413.4	480.4	475.0
Midnight or Equivalent				
Multiple Service	174.2	174.2	174.2	174.2
Series Service	198.9	208.9	242.8	240.0

APPENDIX I

SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED STREET LIGHTING RATES (Cont'd.)

4. SCE proposed Special Condition 10 (reflecting a consolidation of existing Special Conditions 8 and 9) as amended by this decision:

The kilowatthours used to determine the Energy Charge Components changed for HPSV and LPSV lamps as follows:

Nominal Lamp Rating		Per Lamp Per Month					
		Lamp Load including Ballast - Watts		Multiple Service KwH per month		Series Service KwH per month	
Lamp Wattage	Average Initial Lumens	Multiple Service	Series Service	A All-Night	B Mid-Night	C All-Night	D Mid-Night
Incandescent Lamps Extended Service							
	600	55	42	18.975	9.581	16.535	8.354
103	1000	103	75	35.535	17.943	29.528	14.918
202	2500	202	164	69.690	35.188	64.567	32.620
327	4000	327	248	112.815	56.963	97.638	49.327
448	6000	448	347	154.560	78.042	136.614	69.018
690	10000	690	578	238.050	120.198	227.559	114.964
Mercury Vapor							
100	4000	131	125	45.195	22.820	51.675	26.113
175	7900	216	207	74.520	37.627	85.574	43.242
250	12000	301	285	103.845	52.434	117.819	59.537
400	21000	474	445	163.530	82.571	183.963	92.961
700	41000	803	760	277.035	139.883	314.184	158.764
1000	55000	1135	1070	391.575	197.717	442.338	223.523
High Pressure Sodium Vapor							
50	4000	58	64	20.010	10.104	30.746	15.539
70	5800	83	85	28.635	14.459	40.834	20.638
100	9500	117	121	40.365	20.381	58.128	29.379
150	16000	193	174	66.585	33.621	83.590	42.247
200	22000	246	233	84.870	42.853	111.933	56.572
250	27500	313	285	107.985	54.525	136.914	69.198
310	37000	383	349	132.135	66.719	167.660	84.737
400	50000	485	441	167.325	84.487	211.856	107.075
Low Pressure Sodium Vapor							
35	4800	63	51	21.735	10.975	24.225	12.240
55	8000	84	72	28.980	14.633	34.200	17.280
90	13500	131	130	45.195	22.820	61.750	31.200
135	22500	182	185	62.790	31.704	87.875	44.400
180	33000	229	219	79.005	39.892	104.025	52.560

APPENDIX I

SOUTHERN CALIFORNIA EDISON COMPANY

ADOPTED STREETLIGHT RATES

Lamp Type & Size	Series v. Multiple, Burning Schedule	TOTAL LAMP INVENTORY (LS-1, LS-2): LS-1	LS-2	ADOPTED RATES ($ PER LAMP PER MO.) LS-1	LS-2
INCANDESCENT:					
600L *	All Mult	0	0	$7.66	$2.22
	All Sers	0	344	$7.66	$4.83
	Mid Mult	0	0	$7.03	$1.58
	Mid Sers	0	0	$7.03	$4.28
800L *	All Mult	0	0	-	-
	All Sers	0	0	-	-
	Mid Mult	0	0	-	-
	Mid Sers	0	0	-	-
1000L	All Mult	692	4	$8.92	$3.46
	All Sers	79	2,572	$8.92	$5.83
	Mid Mult	0	0	$7.72	$2.27
	Mid Sers	0	0	$7.72	$4.84
2500L	All Mult	182	357	$11.50	$6.04
	All Sers	0	4,175	$11.50	$8.53
	Mid Mult	0	0	$9.16	$3.70
	Mid Sers	0	16	$9.16	$6.37
4000L	All Mult	92	915	$14.76	$9.29
	All Sers	0	3,017	$14.76	$11.07
	Mid Mult	0	0	$10.97	$5.50
	Mid Sers	0	0	$10.97	$7.80
6000L	All Mult	43	104	$17.85	$12.43
	All Sers	0	624	$17.85	$14.08
	Mid Mult	0	0	$12.67	$7.25
	Mid Sers	0	0	$12.67	$9.50
10000L	All Mult	0	27	$24.15	$18.73
	All Sers	0	117	$24.15	$21.08
	Mid Mult	0	0	$16.16	$10.74
	Mid Sers	0	0	$16.16	$13.46
15000L*	All Mult	0	0	-	-
	All Sers	0	0	-	-
	Mid Mult	0	0	-	-
	Mid Sers	0	0	-	-
25000L*	All Mult	0	0	-	-
	All Sers	0	0	-	-
	Mid Mult	0	0	-	-
	Mid Sers	0	0	-	-
Total Incandescent		1,088	20,999		

* Rates for these lamps are presented for illustrative purposes only. Actual rates will be calculated under Special Condition #10.

APPENDIX I

SOUTHERN CALIFORNIA EDISON COMPANY

ADOPTED STREETLIGHT RATES

Lamp Type & Size	Series v. Multiple, Burning Schedule	TOTAL LAMP INVENTORY (LS-1, LS-2): LS-1	LS-2	ADOPTED RATES ($ PER LAMP PER MO.) LS-1	LS-2
MERCURY VAPOR:					
4000L	All Mult	336	1,804	$9.64	$4.19
	All Sers	65	2,725	$9.64	$7.57
	Mid Mult	0	0	$8.12	$2.68
	Mid Sers	0	0	$8.12	$5.84
7900L	All Mult	1,228	2,454	$11.81	$6.40
	All Sers	480	8,715	$11.81	$10.20
	Mid Mult	0	7	$9.31	$3.90
	Mid Sers	0	0	$9.31	$7.34
12000L	All Mult	188	869	$14.06	$8.61
	All Sers	67	1,326	$14.06	$12.71
	Mid Mult	2	11	$10.57	$5.13
	Mid Sers	0	61	$10.57	$8.77
21000L	All Mult	487	6,904	$18.93	$13.11
	All Sers	274	13,071	$18.93	$17.86
	Mid Mult	0	17	$13.43	$7.62
	Mid Sers	0	17	$13.43	$11.69
41000L	All Mult	45	1,752	$27.55	$21.66
	All Sers	10	2,610	$27.55	$27.98
	Mid Mult	0	0	$18.26	$12.37
	Mid Sers	0	0	$18.26	$17.45
55000L	All Mult	16	159	$36.18	$30.30
	All Sers	4	319	$36.18	$37.94
	Mid Mult	0	0	$23.04	$17.16
	Mid Sers	0	0	$23.04	$23.11
Total Mercury Vapor		3,202	42,821		
LOW PRESSURE SODIUM VAPOR:					
4800L	All Mult	0	91	$8.41	$2.42
	All Sers	0	294	$8.41	$5.48
	Mid Mult	0	0	$7.68	$1.70
	Mid Sers	0	0	$7.68	$4.67
8000L	All Mult	109	6,065	$8.96	$2.97
	All Sers	0	11,168	$8.96	$6.28
	Mid Mult	0	116	$7.98	$2.00
	Mid Sers	0	1,090	$7.98	$5.14
13500L	All Mult	49	126	$11.10	$4.19
	All Sers	0	219	$11.10	$8.47
	Mid Mult	0	0	$9.59	$2.68
	Mid Sers	0	6	$9.59	$6.40
22500L	All Mult	26	2,348	$12.70	$5.52
	All Sers	0	2,976	$12.70	$10.56
	Mid Mult	0	2	$10.60	$3.41
	Mid Sers	0	77	$10.60	$7.61
33000L	All Mult	0	666	$13.67	$6.74
	All Sers	0	491	$13.67	$11.83
	Mid Mult	0	0	$11.02	$4.09
	Mid Sers	0	0	$11.02	$8.35
Total LPSV		184	25,755		

APPENDIX I

SOUTHERN CALIFORNIA EDISON COMPANY

ADOPTED STREETLIGHT RATES

Lamp Type & Size	Series v. Multiple, Burning Schedule	TOTAL LAMP INVENTORY (LS-1, LS-2): LS-1	LS-2	ADOPTED RATES ($ PER LAMP PER MO.) LS-1	LS-2
HIGH PRESSURE SODIUM VAPOR:					
4000L	All Mult	28,098	873	$7.74	$2.29
	All Sers	0	3,249	$7.74	$6.01
	Mid Mult	0	0	$7.07	$1.62
	Mid Sers	0	56	$7.07	$4.98
5800L	All Mult	144,509	8,344	$8.35	$2.94
	All Sers	955	2,962	$8.35	$6.81
	Mid Mult	0	39	$7.39	$1.98
	Mid Sers	0	0	$7.39	$5.44
9500L	All Mult	150,395	5,660	$9.25	$3.83
	All Sers	276	803	$9.25	$8.20
	Mid Mult	0	109	$7.89	$2.47
	Mid Sers	0	0	$7.89	$6.25
16000L	All Mult	24,608	5,186	$11.26	$5.80
	All Sers	145	1,215	$11.26	$10.22
	Mid Mult	48	2	$9.02	$3.57
	Mid Sers	0	87	$9.02	$7.42
22000L	All Mult	49,299	11,061	$13.00	$7.18
	All Sers	52	3,967	$13.00	$12.48
	Mid Mult	0	45	$10.15	$4.34
	Mid Sers	0	7	$10.15	$8.73
27500L	All Mult	7,498	9,147	$14.76	$8.92
	All Sers	0	0	$14.76	$13.87
	Mid Mult	0	4	$11.13	$5.30
	Mid Sers	0	0	$11.13	$9.29
37000L	All Mult	0	595	$13.99	$10.74
	All Sers	0	0	$13.99	$16.19
	Mid Mult	0	0	$9.56	$6.31
	Mid Sers	0	0	$9.56	$10.57
50000L	All Mult	1,841	5,172	$19.31	$13.40
	All Sers	2	0	$19.31	$19.52
	Mid Mult	0	0	$13.69	$7.78
	Mid Sers	0	0	$13.69	$12.42
Total HPSV		407,726	58,583		
TOTAL		412,200	148,158		
TOTAL MULTIPLE SERVICE:					
—All Night Service		409,741	74,875		
—Midnight Service		50	509		
TOTAL SERIES SERVICE:					
—Midnight Service		0	1,417		
—All Night Service		2,409	71,358		

APPENDIX I

SOUTHERN CALIFORNIA EDISON COMPANY

ADOPTED STREETLIGHT RATES

SCHEDULE NO. LS-3

	Rate $
Customer Charge:	
Series Service	108.75
Multiple Service	8.62
Subtotal	
Energy Charge:	
KWH:	0.07536

Customer Charges determined:	Series	Multiple
RD Transformer	74.57	0
Customer Billing (1)	4.74	4.74
System Connection (1)	3.17	3.17
Metering (1)	26.27	0.71
Total Customer Charge	108.75	8.62

APPENDIX I

SOUTHERN CALIFORNIA EDISON COMPANY

ADOPTED STREETLIGHT TATES

SCHEDULE NOS. LS-2 & LS-3
OPTIONAL RELAMPING SERVICE

Nominal Lamp Rating: Wattage	Lumens	Adopted Rate per Lamp $
High Pressure Sodium Vapor Lamps:		
50	4,000	0.40
70	5,800	0.40
100	9,500	0.41
150	16,000	0.42
200	22,000	0.42
250	27,500	0.42
400	50,000	0.44

APPENDIX I

SOUTHERN CALIFORNIA EDISON COMPANY

ADOPTED STREETLIGHT RATES

SCHEDULE NO. OL-1

Nominal Lamp Rating: Wattage	Lumens	Number of Lamps	Proposed LS-1 Rate Per Lamp $	Adjustment to LS-1 Rate $	Adopted OL-1 Rate Per Lamp $
Mercury Vapor Lamps:					
175	7,900	1,856	11.81	1.11	10.70
400	21,000	650	18.93	1.11	17.82
High Pressure Sodium Vapor Lamps:					
70	5,800	5,734	8.35	1.11	7.24
100	9,500	5,082	9.25	1.11	8.14
200	22,000	5,219	13.00	1.11	11.89
TOTAL		18,541			
Pole Charge		6,250			2.20

A.86-12-047, I.87-01-017 /ALJ/FSF,SSM/jt *
CACD/llg,jh

APPENDIX I

SOUTHERN CALIFORNIA EDISON COMPANY

ADOPTED STREETLIGHT RATES

SCHEDULE DWL

	Composite Rates RATE A	RATE B	RATE C
Facilities Cost	5.25000	0.00000	0.00
Billing	0.15550	0.15550	0.00
System Connection	0.18360	0.18360	0.00
Relamp	0.40270	0.00000	0.40
Maintenance (Normal)	0.55304	0.00000	0.00
Cable and Photo Cell	0.00000	1.81000	0.00
Energy & Demand (32.341 kWh @$.07536)	2.43722	2.43722	0.00
Per Lamp per Month	8.99	4.59	0.40

(END OF APPENDIX I)

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List of Appearances

Applicant: Mark L. Sutton, Richard K. Durant, Carol B. Henningson, Stephen E. Pickett, and James M. Lehrer, Attorneys at Law, for Southern California Edison Company.

Interested Parties: Jackson, Cole, Tufts & Black, by Allan J. Thompson and Linda Jones, Attorneys at Law, for CLECA (California Large Energy Consumers Association); Barbara R. Barkovich, for California Steel Producers Group and CLECA; Drazen-Brubaker, by Donald W. Schoenbeck, Paul J. Kaufman, Attorney at Law (Oregon), Messrs. Lindsay, Hart, Neil & Weigler, by Clyde E. Hirschfeld, Attorney at Law, and Lindsay & Hart, by Michael Peter Alcantar, Attorney at Law, for Cogenerators of Southern California; Bill L. Kurtz, Jr., Attorney at Law (Colorado), for Champlin Petroleum Co.; Edward Duncan, for Consumers Coalition of California; Ernest E. Gilbert, Attorney at Law, for Richard H. Wesselink, et al.; Roger Schwartz, Jon Elliott, and Mike Florio, Attorneys at Law, and Sylvia M. Siegel, and Law Office of Kathryn Burkett Dickson, by Joel R. Singer, Attorney at Law, for Toward Utility Rate Normalization; McCracken, Byers & Martin by David J. Byers, Attorney at Law, and Reed V. Schmidt, for California City & County Street Light Association; Morrison & Foerster, by Robert Chan and Jerry R. Bloom, Attorneys at Law (New York), for California Cogeneration Council; William L. Reed, Stephen A. Edwards, and Michael R. Weinstein, Attorneys at Law, and Barton M. Myerson, for San Diego Gas & Electric Company; Brobeck, Phleger & Harrison, by Gordon E. Davis, Attorney at Law, for California Manufacturers Association; Graham & James, by Boris Lakusta, Martin Mattis, Robert Lopardo, and James V. Shepherd, Attorneys at Law, for California Hotel and Motel Association; Harry K. Winters, for University of California; William L. Knecht, Attorney at Law, by Philip C. Presber, for California Association of Utility Shareholders; David B. Follett and Roy M. Rawlings, Attorneys at Law, for Southern California Gas Company; Norman Furuta, Attorney at Law, and G. Douglas Ivins, for Federal Executive Agencies; Gilbert Chong, Attorney at Law, for Department of the Navy; Tom Dalzell, Attorney at Law, for Local 47, International Brotherhood of Electrical Workers, and Local 246, Utility Workers Union of America; Don Salow, for Association of California Water Agencies; Steven A. Geringer, Attorney at Law, for California Farm Bureau Federation; Biddle & Hamilton, by Richard L. Hamilton, Attorney at Law, for Western Mobilehome Association; John D. Quinley, by W. Walzer, for

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List of Appearances

Cogeneration Service Bureau; Sutherland, Asbill & Brennan, by Earle H. O'Donnell, Attorney at Law (District of Columbia), for Federal Paper Board Company; Downey, Brand, Seymour & Rohwer, by Philip A. Stohr, Attorney at Law, for Union Carbide Corporation; Grueneich & Lowry, by Edwin F. Lowry and Dian Grueneich, Attorneys at Law, for Department of General Services, State of California; William B. Marcus, for JBS Energy, Incorporated; Gary B. Simon, for El Paso Natural Gas Company; David R. Branchcomb, for Henwood Energy Services, Inc.; Robert Gnaizda, Attorney at Law, for Amerian G.I. Forum, Filipino American Political Association; Maureen Church, for Barakat, Howard & Chamberlin; Messrs. Kronick, Moskovitz, Tiedemann & Girard, by John L. Bukey, Attorney at Law, for Schools Committee to Reduce Utility Bills; Judith Alper, Attorney at Law, for Independent Power Corporation; Susan Ackerman, Attorney at Law, for Bonneville Power Administration; Downey, Brand, Seymour & Rohwer, by Christopher Ellison, Attorney at Law, for Mobil Oil Corp., Air Products & Chemical, Inc., Big Three Industries, Inc., General Motors Corp. (Delco), and Metal Container Corp. of California; Bob Weisenmiller, for Morse, Richard, Weisenmiller & Associates, Inc.; A. Kirk McKenzie and Antonio Radillo, Attorneys at Law, for California Energy Commission; Douglas A. Ames, for Thermal Energy Storage Manufacturers'/Contractors' Association; William L. Demyers, for self; Roger J. Peters, Attorney at Law, for Pacific Gas and Electric Company; Jeffrey P. Harris, for California Institute for Energy Efficiency; and Robert Lobue and Chris Hash, for California Citrus Mutual.

Public Staff Division: Thomas P. Corr and Philip Scott Weismehl, Attorneys at Law, Robert Feraru, Natalie Hanson, John A. Yager, and David Fukutome.

(END OF APPENDIX J)

APPENDIX K
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List of Acronyms

A. - Application
AB - Assembly Bill
A&G - Administrative and General
ACWA - Association of California Water Agencies
AER - Annual Energy Rate
ALJ - Administrative Law Judge
ANPP - Arizona Nuclear Power Project
APS - Administrative, Professional, and Supervisory
ARA - Attrition Rate Adjustment

BCR - Benefit Cost Ratio
BPA - Bonneville Power Authority

Cal-Neva - California/Nevada Community Action League
CAL-SLA - California City and County Street Light Association
CCC - California Cogeneration Council
CEC - California Energy Commission
CHMA - California Hotel and Motel Association
CIA - Commercial/Industrial/Agricultural
CLECA - California Large Energy Consumers Association
CLMAC - Conservation Load Management Adjustment Clause
CMA - California Manufacturers Association
Council - California Utility Research Council
CPCN - Certificate of Public Convenience and Necessity
CPUC - California Public Utilities Commission
CSC - Cogenerators of Southern California
CSPG - California Steel Producers Group

List of Acronyms

D. - Decision
DC - Direct Current
DC Expansion - Sylmar-Pacific High Voltage Direct Current Intertie Expansion Project
DCF - Discounted Cash Flow
DGS - State Department of General Services
DRI - Data Resources Incorporated
DSM - Demand Side Management

E&C - Commission's Evaluation and Compliance Division
ECAC - Electric Cost Adjustment Clause
Edison - Southern California Edison Company
EPMC - Equal Percent of Marginal Cost
ER 6 - Electricity Report 6
ERAM - Electric Revenue Adjustment Clause
ERI - Energy Reliability Index
EUE - Expected Unserved Energy

F/MBE - Female/Minority Business Enterprises
Farm Bureau - California Farm Bureau
FEA - Federal Executive Agencies
FERC - Federal Energy Regulatory Commission
Four State Committee - California/Arizona/New Mexico/Texas

GNP - Gross National Product
GRI - Gas Research Institute
gWh - Gigawatt Hours

List of Acronyms

I. - Order Instituting Investigation
IAM - Incremental Analysis Model
IEP - Independent Energy Producers
IER - Incremental Energy Rate
ILS - Integrated Living Schedule
IMAAC - Intermediate Major Additions Adjustment Clause
Institute - Organizing Committee for the California Institute for Energy Efficiency

kW - Kilowatts
kWh - Kilowatt-hour

LADWP - Los Angeles Department of Water and Power
LOLP - Loss of Load Probability

MAAC - Major Additions Adjustment Clause
MDS - Minimum Distribution System
MOU - Memorandum of Understanding
MW - Megawatts

NOI - Notice of Intent
NRC - Nuclear Regulatory Commission

O&M - Operations and Maintenance
OCLD - Original Cost Less Depreciation

Palo Verde - Palo Verde Nuclear Generating Station Units
PCAM - Production Cost Analysis Model

List of Acronyms

PERC - Plant Expenditure Review Committee
PGE - Portland General Electric Company
PG&E - Pacific Gas & Electric Company
PHFU - Plant Held for Future Use
PNW - Pacific Northwest
PP&L - Pacific Power & Light Company
PSD - Commission's Public Staff Division
PSW - Pacific Southwest
PU - Public Utilities Code
PURPA - Public Utility Regulatory Policy Act

QF - Qualified Facilities

R. - Order Instituting Rulemaking
RCFD - Residential Conservation Financing Program
RCN - Replacement Cost New
RD&D - Research demonstration and Development
RIM - Rate Impact Test
RO - Regulated Output
ROE - Return on Common Equity
RTP - Real Time Pricing
RV - Recreational Vehicle

SAPC - System Average Percent Change
SCRUB - Schools Committee To Reduce Utility Bills
SDG&E - San Diego Gas & Electric Company
SoCal - Southern California Gas Company
SONGS - San Onofre Nuclear Generating Station Units
SOP - Super Off Peak

List of Acronyms

TES - Thermal Energy Storage

TESMAC - Thermal Energy Storage Manufacturers' and Contractors' Association

TFP - Total Factor Productivity

TOU - Time of Use

TSM - Transformer, Service Drop and Meter

TURN - Toward Utility Rate Normalization

WMA - Western Mobilehome Association

3-Rs - R.86-10-001 (Risk, Return, and Ratemaking)

#8

Additional language for Item 8, President Hulett's alternate on the DC upgrade. After the first full paragraph on page 75, to insert the following:

"We are encouraged that Edison is using more sophisticated modeling techniques such as the decision tree model used in its showing here. Any model, however, is only as good as the assumptions upon which it is based. In this regard, we put all parties on notice that in cost-effectiveness calculations it is inappropriate to use a nominal carrying charge rate, to not account for seasonal differences in capacity values, and to not recognize existing excess capacity circumstances."

Keep

Decision PROPOSED DECISION OF ALJs FERRARO AND MYERS

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. (Electric) (U 338 E)	Application 86-12-047 (Filed December 26, 1986)
Order Instituting Investigation into the rates, charges, and practices of the Southern California Edison Company	I.87-01-017 (Filed January 14, 1987)

(Appearances are listed in Appendix J.)

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INTERIM OPINION

I. Summary of Decision

This decision orders Southern California Edison Company (Edison) to reduce its base revenues by $57.7 million or 1.0% and authorizes Edison to increase its major additions adjustment clause (MAAC) by $73.7 million or 1.4 percent. These rate changes, which are to become effective January 1, 1988, will result in an increase of $1.64 or 4.0% per month for a typical residential customer using 500 kWh per month.

In approving the increase in MAAC rates a special procedure is established to review the reasonableness of Edison's expenditures for capital projects costing over $50.0 million. Through this procedure Edison will be allowed to increase rates by an amount equal to 75% of a project's revenue requirement, subject to refund.

Additionally, a return on common equity (ROE) of 12.75% is authorized, $91.8 million is adopted as a ratemaking cost cap for Edison's Sylmar-Pacific Northwest intertie expansion project (DC Expansion), Edison's electric vehicle program is not funded, increased funding for an expanded female/minority business enterprises (F/MBE) program is authorized, guidelines for evaluating plant held for future use (PHFU) are adopted and a procedure is created for funding Edison's hazardous waste management program. The significant reductions in Edison's requested revenue requirement are listed below.

INTERIM OPINION

I. Summary of Decision

This decision orders Southern California Edison Company (Edison) to reduce its base revenues by $56.0 million or 1.0% and authorizes Edison to increase its major additions adjustment clause (MAAC) by $26.0 million or 0.5%. These rate changes, which are to become effective January 1, 1988, will result in an increase of $1.64 or 4.0% per month for a typical residential customer using 500 kWh per month.

In approving the increase in MAAC rates a special procedure is established to review the reasonableness of Edison's expenditures for capital projects costing over $50.0 million. Through this procedure Edison will be allowed to increase rates by an amount equal to 75% of a project's revenue requirement, subject to refund.

Additionally, a return on common equity (ROE) of 12.75% is authorized, $91.8 million is adopted as a ratemaking cost cap for Edison's Sylmar-Pacific Northwest intertie expansion project (DC Expansion), Edison's electric vehicle program is not funded, increased funding for an expanded female/minority business enterprises (F/MBE) program is authorized, guidelines for evaluating plant held for future use (PHFU) are adopted and a procedure is created for funding Edison's hazardous waste management program. The significant reductions in Edison's requested revenue requirement are listed below.

Major Revenue Requirement Reductions
(Dollars in millions)

	Amount
Return on Equity	$ 47.6
Additional Productivity	34.8
Steam Production Accounts: 512 & 513	16.0
A & G	
Customer Growth	3.2
Medical	4.3
Insurance	1.8
Nuclear Fuel	9.3
Demand Side Management	6.3
Nuclear Production	4.3
Distribution	4.0
Coal Inventory	1.8
Plant Held for Future Use	1.1
Customer Accounts	0.5
Miscellaneous	1.7
Total	$136.7

By this decision, the Commission continues its commitment to marginal cost ratemaking. Marginal energy, demand, distribution, and customer costs are adopted and used in the revenue allocation process. Additionally, avoided energy and capacity costs are adopted for use in developing prices for power purchased by Edison from qualifying facilities.

Revenue allocation is based on an Equal Percent of Marginal Cost methodology aimed at achieving cost-based rates, providing accurate price signals related to energy consumption, and discouraging uneconomic bypass of the Edison system by customers with the potential to generate their own power. A cap on the revenue increases to customer classes and rate groups, however, is adopted for the test year set at 5% over the system average percentage change. This cap is necessary to mitigate the adverse rate impacts for certain customer groups which would result from moving to a full EPMC revenue allocation for 1988.

Major Revenue Requirement Reductions
(Dollars in millions)

	Amount
Return on Equity	$ 47.6
Additional Productivity	34.8
Steam Production Accounts: 512 & 513	13.3
A & G	
Customer Growth	4.7
Medical	4.3
Insurance	1.8
Nuclear Fuel	9.3
Demand Side Management	6.3
Nuclear Production	4.3
Distribution	4.0
Coal Inventory	1.8
Plant Held for Future Use	1.2
Customer Accounts	0.9
Miscellaneous	0.6
Total	$134.9

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The rate structures adopted for each customer group and for each schedule within those groups are based on current Commission rate design policies. The adopted rate structures therefore reflect, to the extent possible and practical, cost-based rates designed to provide accurate and understandable price signals to which the customer can respond, to reflect a customer's usage patterns and characteristics, to recover the customer group's revenue requirement, and to mitigate any negative bill impacts.

II. Introduction

This decision is the culmination of a fourteen month process which began in September 1986 with Edison's tendered Notice of Intent (NOI). The decision is divided into three major sections:

1. Results of Operation - traditional revenue requirement items, such as operating expenses, taxes, depreciation, and plant.
2. Major Issues - policy issues which affect Edison's revenue requirement including; cost of capital, resource planning, research, design and development (RD&D), productivity, employee compensation, F/MBE, affiliate transactions, hazardous waste, and demand side management.
3. Rates - issues associated with how Edison's revenue requirement should be recovered and payments to qualified facilities (QFs). This section is divided into five categories: marginal cost, revenue allocation, rate design, bypass, and cogeneration.

With the exception of the summary of the decision and procedural background sections, all dollars in this decision are on a total company basis and in 1985 dollars, unless otherwise noted. Dollars referenced in the summary of decision and procedural background sections are in 1988 dollars and California Public Utilities Commission (CPUC) jurisdictional. Attached to this decision are tables setting forth the adopted revenue requirement and rate design. The adopted summary of earning is shown on page 30 of Appendix C. Included as the final attachment is a list of acronyms to assist the reader.

Typically, general rate cases for utilities the size of Edison are long and difficult. While we have come to expect this, two items have made this proceeding even more trying than previous Edison general rate cases. First, to comply with Public Utilities Code (PU) Section 311, which requires the release of Administrative Law Judge (ALJ) proposed decisions at least 30 days prior to issuance of the Commission's decision, the rate case schedule was shortened. This resulted in multiple briefing dates and a condensed hearing schedule. Second, the parties have intensified their participation in the areas of marginal cost, rate design, and resource planning. Because of these changes we have issued Order Instituting Rulemaking (R.) 87-11-012 to consider modifications to the current rate case plan.

Finally, although the sailing was often rough, we wish to thank the interested parties, PSD, and Edison for their cooperation in guiding this rate case through the uncharted waters of PU Section 311.

III. Procedural Background

On December 26, 1986, Edison filed Application (A.) 86-12-047 requesting authority to increase base rate revenues by $301.5 million or 5.4% for test year 1988. Edison also requested attrition increases for 1989 and 1990. Since the filing of

A.86-12-047, Edison has made considerable revisions and currently is requesting an increase of $79.0[1] million or 1/4 percent.[1]

The major causes for the reduction in Edison's request were the removal from base rates of $79 million in revenue requirement associated with three large plant additions: Balsam Meadow hydroelectric generation plant, Devers-Valley-Serrano transmission line, and DC Expansion, a reduction in the requested return on equity and a change in the capital structure, $67 million, and lower depreciation rates, $96 million.

On February 2, 1987, a prehearing conference was held in Los Angeles to discuss procedural matters including a modified rate case schedule to reflect the requirements of PU Section 311. Additionally, five days of public hearings, a Commission en banc public hearing in Pomona, 53 days of evidentiary hearings, and Commission en banc oral arguments were held. During the course of this proceeding 55 public witnesses made statements, 96 expert witnesses testified, and 317 exhibits were received.

An Order Instituting Investigation (I.) 87-01-017 into the rate changes and practices of Edison was issued on January 14, 1987. This order serves as the procedural vehicle for considering a reduction in Edison's rates and was consolidated with A.86-12-047.

In accordance with PU Section 311 the ALJ's draft decision, prepared by ALJs Sara S. Meyers and Francis S. Ferraro, was issued on November 20, 1987.

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1 This decision increases Edison's request to reflect the exclusion of $19.4 million of CLMAC revenues from present rate revenues. Further details are provided in the section of revenues at present rates.

CLECA/CSPG, PG&E, SDG&E, WMA, RV Park Owners, Farm Bureau, and ACWA.

These comments have been reviewed and carefully considered by the Commission. Any changes required by those comments have been incorporated in this final decision.

IV. Results of Operations

A. Escalation

1. Labor

Edison and Public Staff Division (PSD) are in agreement as to the labor escalation rates to be used to escalate nominal dollars into constant dollars and to forecast wage and salary increases for operation and maintenance expense. The labor escalation rates for the years through 1988 are to be based on Edison's actual negotiated union contract agreements, adjusted to reflect the effective date of the agreements. The labor escalation rates for the years 1989 and 1990 are to be determined in Edison's attrition filings by the prior years percentage change in the Consumer Price Index-Wage Earners. For this decision we will adopt the agreed upon labor escalation rate of 3.5% for both 1987 and 1988.

2. Non-Labor

Edison and PSD are in agreement regarding the methodology to be used in developing non-labor escalation rates in deriving the test year's and attrition years' expenses. This methodology uses Data Resources, Incorporated's (DRI) forecast of 25 material and labor price indexes and a gross national product deflator index to develop utility specific non-labor escalation rates. We will adopt Edison's and PSD's recommended non-labor escalation rates of 2.99% for 1987 and 4.41% for 1988.

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Sales And Revenue

3. Sales Forecast

Edison and PSD are in agreement with respect to the forecast of kilowatt-hour (kWh) sales. We will adopt their forecasted 1988 kWh sales as shown below:

Summary of Kilowatt-Hour Sales
(Millions of kWh)

Class of Service	Adopted 1988
Residential	19,832
Agricultural & Pumping	2,077
Small & Medium Power	21,798
Large Power	20,351
Streetlighting	471
Resale	850
Net Edison	65,379
Resale - Special Contracts	580
Total	65,959

4. Revenue at Present Rates

The present rate revenues calculated by Edison for the 1988 test year were developed from the base rate levels in effect at the time this filing was prepared. PSD is in agreement with Edison's present rate revenues as derived from the sales forecast previously discussed. A review of these revenues indicates that the conservation/load management adjustment clause (CLMAC) revenues are included in present revenues.

The CLMAC revenues are design to recover prior years' conservation and load management expenses and are not adjusted by this decision. As such, it is inappropriate to include CLMAC revenues in this decision's adopted present revenues. While this has no affect on the adopted revenue requirement it does increase the difference between present and adopted base rate revenues by $19.4 million. We will adopt Edison's present rate revenues excluding CLMAC revenues. The adopted present rate revenues are shown in Appendix C.

5. Other Operating Revenue

Other operating revenues are revenues obtained by a utility from other than the sale of electric energy. Other operating revenues include return check charge, service establishment charges, transmission of electricity for others, joint pole rentals, added facilities revenues, and miscellaneous revenues.

PSD agreed with Edison's original estimate of other operating revenues. However, PSD proposed the addition of certain revenues pertaining to the gains on property sold, timber sales, and subsidiary operations. The issue of subsidiary revenues is addressed in the section on affiliate transactions.

PSD's recommendation on gains from property sold involves three distinct proposals. PSD's first proposal involves the inclusion of an estimate for account 411 (gains/losses on the disposition of utility property) in the test year to reflect future gains or losses on property held for future use. PSD utilized a five-year historical average in determining the estimated 1988 revenue level for account 411.

PSD's second proposal is to include an estimate for revenues derived from properties sold from account 121 (non-utility property) that were originally in account 105. PSD recommends that these revenues should be recorded in account 411, an above-the-line revenue account for test year 1988. PSD proposed a two-year historical average in determining the 1988 estimated revenue for this item.

PSD's third proposal relating to gains or losses on the sale of utility plant involves property sold directly out of account 101 (electric plant-in-service) and account 103 (experimental electric plant unclassified). PSD recommends that revenues derived from property sold directly out of these accounts at any time during their useful life should go directly to the ratepayer. The gain or loss on property originally in accounts 101 or 103 and transferred to account 121 prior to sale should be allocated between the shareholder and ratepayer based upon the time it was in rate base and in non-utility property. PSD again proposed a two-year average in determining the 1988 estimated revenue for this item.

The last item PSD proposed for inclusion in other operating revenues is revenues derived from timber sales. PSD proposes the use of a five-year historical average in determining the estimated 1988 timber revenue.

Edison agrees with PSD that revenues associated with gains or losses from property sold and timber sales should be included in the 1988 test year. However, Edison believes that the test year estimates should be based upon a five-year historical average so that all of PSD's proposals are consistent. PSD has agreed with Edison's proposal.

Based upon a five-year average for each of the above items, Edison increased its estimate of other operating revenues for test year 1988 by $2.4 million.

B. Operating Expenses

Operating expenses are all costs associated with operating the utility, including the cost of operating and maintaining the utility's facilities.

1. Steam Production Expense

Steam production expenses represent the cost, excluding fuel, of operating and maintaining Edison's fossil fuel electric generation units. Edison requests $209.2 million for steam production expenses in test year 1988. PSD recommends that Edison's request be reduced by $3.1 million for three specific projects and an additional $5.9 million in the area of overhaul expense.

To estimate steam production expense, Edison collected seven years of recorded expenses (1979-1985), by Federal Energy Regulatory Commission (FERC) account. Adjustments were applied to remove unusual activities or items of expense that were not appropriate for estimating based on recorded data. The recorded data, after adjustments, was escalated to constant 1985 dollars and trended using a linear least-squares analysis on a labor, non-labor basis by account. Trended results that met one of the generally accepted statistical measures of a coefficient of determination, R^2, of .60 and gre ter or a T-statistic of 2 or greater were retained if judgment also indicated that the circumstances that caused the trend in the recorded data would continue into the estimated period. Trends not meeting these measures were discarded and in most cases a seven-year historical average was substituted.

Future year adjustments such as those removed from the recorded years were estimated in 1985 dollars and added to the trended/averaged amounts in the years in which they are expected to occur. The total of the adjustments and the trended/averaged portion were escalated as appropriate resulting in the estimated amounts for 1986-1988.

PSD followed Edison's estimating methodology with the exception of four specific adjustments. As part of the examination process, PSD made a detailed on-site field review of overhaul work scopes and specific adjustments with most generating station management and engineering staffs. Additionally, PSD reviewed accounting and administrative practices and reviewed the application and workpapers.

The remaining issues between Edison and PSD involve: (1) proposed modification of 480 MW boilers for minimum load operation, (2) proposed modification of 215 MW units to permit two-shifting, (3) research, development and demonstration expenses, and (4) level of overhaul expenses. An additional issue was raised by Federal Executive Agencies (FEA). FEA asserts that Edison should not fully recover expenses for abnormal/non-recurring maintenance for turbine rotor repairs. This issue amounts to a test year reduction of $4.4 million. A complete discussion of the boiler modifications and RD&D expenses is contained in the resource plan and the RD&D section, respectively. The remaining issues are discussed in the following sections and detailed in the table below:

Steam Production Expense
(1985 Dollars)

Issue	Edison	PSD	FEA	Adopted
		(Dollars in Thousands)		
Adjustments:				
Overhaul Expense	$40,680	$34,817	$ -	$37,185
Abnormal/Non-Recurring Maintenance	5,947	-	1,501	1,982

2. Overhaul Expense

PSD recommends that Edison's forecasted expenditures for steam generation unit overhauls be reduced by $5.9 million. PSD states that Edison proposes to increase accounts 512 and 513 by over 50% due to the development of new criteria to schedule steam generating unit overhauls. While these new criteria are intended to reduce the number and duration of overhaul outages, PSD argues that Edison has not demonstrated how these reductions relate to savings of forecasted O&M expenses. To recognize the yearly fluctuations in overhaul activities, PSD recommends a seven-year average (1979-1985) of overhaul expenses be used to for test year 1988.

We agree with PSD that Edison has neglected to fully justify a sizable increase in overhaul expenses. Edison states that it expects the new overhaul criteria to reduce routine activities during every overhaul, but fails to quantify this benefit. Without adequate justification, such as a cost-effectiveness analysis, we will average overhaul expenses. However, consistent with the averaging methodology used for other operating revenues and certain expense estimates, we find the use of a five-year average of recorded overhaul expenses more appropriate than PSD's seven-year average. We will adopt a five-year average of recorded overhaul expenses and reduce Edison's requested steam production expenses by $3.5 million.

CORRECTION

THIS DOCUMENT HAS

BEEN REPHOTOGRAPHED

TO ASSURE

LEGIBILITY

Steam Production Expense
(1985 Dollars)

Issue	Edison	PSD	FEA	Adopted
		(Dollars in Thousands)		
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3. Abnormal/Non-Recurring Maintenance

FEA contends that repairs planned for the low pressure turbine rotor during Redondo generating station unit 7's next overhaul are abnormal/non-recurring maintenance and the expenses should not be fully recovered in the test year. FEA recommends the expenses be recovered over a fifteen-year period. Although turbine repairs of this magnitude are not done on any one unit on a routine annual basis, Edison states they are a normal expected activity on a cyclic basis. As Edison's witness testified:

> "...this type of work is planned for all the units in this class in subsequent years..."

While FEA's proposal only recognizes the funding requirement for one unit every 15 years, Edison's request assumes this type of repair will occur annually.

We believe that neither of these approaches yields an appropriate expense level for test year 1988. We consider three years to be representative of the frequency of this type of repair and will reduce Edison's request by $4.0 million to reflect this.

4. Hydraulic Production Expense

Edison's original estimate of hydro production expense was $20.9 million. Reductions by Edison have lowered this amount to $20.5 million.

Both Edison and PSD recommend that $20.5 million be adopted for test year hydro production expense.

5. Other Production Expense

Edison's original estimate for other production expense was $29.5 million. Reductions by Edison and the transfer of $10.0 million for hazardous waste management costs to a subsequent proceeding have lowered this amount to $17.2 million.

Both Edison and PSD recommend that $17.2 million be adopted for test year other production expense.

6. Nuclear Power Production Expense

Edison and PSD are in agreement with respect to the test year 1988 level of operation and maintenance (O&M) expense for the San Onfre nuclear generating station units (SONGS). Edison and PSD are also in agreement that an increase in Nuclear Regulatory Commission (NRC) fees should receive rate relief for test year 1988 if it is enacted by legislation during this proceeding. If legislation is enacted subsequent to this proceeding, both Edison and PSD consider rate relief through the attrition mechanism appropriate. Since legislation has not been enacted, we will allow Edison to seek rate relief for increased NRC fees through its attrition mechanism. Finally, Edison, PSD, and FEA are in agreement with the continuation of the flexible refueling mechanism adopted in Edison's last general rate case for use with SONGS and Palo Verde nuclear plant refuelings.

Although PSD agrees with Edison's SONGS O&M expense estimates, it recommends a $2.3 million reduction in Edison's O&M expense level for Palo Verde nuclear generating station units (Palo Verde), including refueling. While this decision only authorizes O&M and refueling expenses for Palo Verde 1 and 2, Edison should use the same level of expenses for Palo Verde 3 when it becomes commercially operational. Edison's A.87-08-054 will address the implementation of rate changes associated with Palo Verde 3 O&M and refueling expenses. Additionally, FEA takes exception to Edison's O&M estimate with regard to two items totaling $5.9 million.

Each of the issues and their dollar impact on test year 1988 are identified in the following table:

Nuclear Power Production Expense Issues

Issue	Edison	FEA	PSD	Adopted
	(Dollars in Thousands)			
SONGS 3 Steam Generator Chemical Cleaning	$ 4,884	$ 0	$ -	$ 1,628
SONGS 1 Spent Nuclear Fuel	970	0	-	0
Palo Verde Refueling Outage	3,960	0	2,772	3,960
Palo Verde O&M Expense	18,464	-	17,379	18,464

Edison developed its revised estimate of nuclear production expense for SONGS 1, 2 and 3 using recorded O&M expense data for the years 1984-1986. Historical adjustments were applied to the recorded O&M expense data for each year to remove unusual, one-time, or cyclical expenses. The resulting average-year expenses were then adjusted for expenses expected to occur in future years. These future-year adjustments included reductions in expense because of several identified productivity measures. Refueling outages were specifically identified for each year by unit rather than normalized because of Edison's request to have a flexible refueling outage schedule during the test and attrition-year period of 1988-1990.

For Palo Verde 1, 2 and 3, Edison utilized the zero-base O&M expense estimates provided by Arizona Nuclear Power Project (ANPP). With the sole exception of the addition of new NRC fees (imposed on all nuclear units) not included in ANPP's estimate, Edison accepted ANPP's total O&M expense estimate as reasonable, but concluded that the base O&M and refueling outage expense needed adjustment. Without changing ANPP's total O&M expense estimate, Edison scaled-up the refueling outage expense estimates provided by ANPP to reflect 70-day refueling outages rather than the 49-day refueling outages assumed in the expense estimate. Since the total

O&M expense does not change, scaling-up refueling outage expense results in a lower anticipated base level O&M expense.

PSD recommends that the level of O&M expenses for Palo Verde be determined from the 1985 average O&M expenses for 24 large nuclear units. This estimating methodology is proposed by PSD because Palo Verde 1 and 2 have recently gone into commercial operation and as a result there is an absence of operating history for developing ratemaking estimates. In support of this approach PSD states that the initial ratemaking O&M expense estimates for SONGS 2 and 3 were developed from an average of other nuclear units. Finally, PSD points out that SONGS 2 and 3 O&M expenses in the early years were well in excess of the average of other nuclear units, but after approximately two years of operation Edison was able to reduce O&M expenses below the average. Since Palo Verde 1 and 2 are approaching two years of operation, PSD believes that they should follow the pattern of SONGS and approach the national average for O&M expenses.

Edison is opposed to PSD's averaging methodology for determining the Palo Verde 1 and 2 O&M expense level. Edison states that the comparative study used by PSD is not precise, does not consider the fundamental differences which exist among nuclear plants, and is only useful to establish a zone of reasonableness. Additionally, Edison argues that the comparative study used by PSD shows that O&M expenses varied by at least $20 million above or below the average and were 11.8% higher in 1986.

For the costs associated with Palo Verde refueling outages PSD recommends that ANPP's estimate based on 49-day outages be used in place of Edison's proposed 70-day outages. This results in a $1.2 million reduction in Edison's requested outage costs. Edison responds by stating that ANPP revised its outage duration estimate to 70-80 days and that Edison's use of 70 days reflects its experience at SONGS 2 and 3.

Because of the lack of recorded data from which to judge the reasonableness of Edison's O&M expense level for Palo Verde, PSD proposes that an average O&M expense level for other nuclear units be used. Although PSD's approach is conceptually valid, its application is flawed.

First, PSD's average does not take into consideration geographical differences among units. Second, refueling expenses were not excluded. Third, PSD did not attempt to reconcile the sizable difference between 1985 and 1986 average O&M expenses. In contrast the ANPP managers and supervisors prepared a detailed zero-based budget in which Edison was a participant, PSD reviewed ANPP's budget and had no specific adjustments, and Edison reduced its share of ANPP's budgeted O&M expenses by $1.2 million.

Because of the detailed analysis and review process used to develop and judge ANPP's estimates, we find Edison's O&M expense estimates for Palo Verde reasonable. With respect to Edison's refueling outage expense estimate, we consider Edison's use of 70-day outages a reasonable approximation for ratemaking based on recorded experience at SONGS 2 and 3.

FEA recommends that chemical cleaning costs totaling $4.9 million for SONGS 3 be disallowed and $2.9 million for SONGS 1 spent nuclear fuel reprocessing be excluded from rates. These adjustments would reduce Edison's request for test year 1988 by $5.9 million.

Edison states that the chemical cleaning process will be performed in conjunction with the replacement of feedwater heaters with new components that do not contain copper-bearing material. FEA cites Edison's testimony which claims this is a one-time expense which does not represent a normal refueling outage activity. As a result FEA recommends the entire amount be excluded from rates. Edison argues that this expense is included in its estimate of refueling outage expense and as such is part of the mechanism which allows for a flexible refueling schedule. Finally, while Edison agrees that this is a one-time expense for SONGS 3, it also plans to clean SONGS 2 in the future.

The fact that this is a one-time expense does not preclude Edison from recovering its cost. We are satisfied with Edison's justification for cleaning the steam generators to mitigate the effects of copper contamination. However, because this is a one-time expense we will allow Edison to recover this cost over the rate case cycle of three years.

Edison also included an adjustment for test year 1988 to cover the planned write-off to expense of one-third of the costs derived from a contractual agreement with General Electric Company. This contract was for the reprocessing of SONGS 1 spent nuclear fuel leased from the Atomic Energy Commission. FEA takes the position that the recovery of this expense which was incurred from 1976 through 1983 is retroactive ratemaking and should be disallowed.

Edison states that the Nuclear Waste Policy Act enacted into law in January 1983 made it necessary for Edison to analyze its accounts which contained spent nuclear fuel costs. As a consequence of Edison's evaluation of those accounts, the cost associated with the reprocessing agreement were identified as appropriate for write-off to expense in October 1986. This general rate case is the first opportunity for Edison to seek rate recovery for that expense. Finally, Edison claims that a similar write-off of spent nuclear plutonium salvage costs was allowed in test year 1983.

We agree with FEA that recovery of expenses previously incurred without our prior approval of a mechanism for tracking these costs for later recovery is retroactive ratemaking. Edison claims that it was afforded similar ratemaking treatment in its test year 1983 rate case. However, our review of Edison's 1983 general rate case decision, Decision (D.) 82-12-055, indicates that Edison was only allowed to recover projected expenses associated with permanent disposal of spent nuclear fuel. We will disallow Edison's request for $2.9 million in spent nuclear fuel costs amortized over three years.

C. Transmission Expense

Edison's original estimate for transmission expense was $77.7 million. Reductions by Edison have lowered this amount to $75.3 million.

Both Edison and PSD recommend that $75.3 million be adopted for test year transmission expense.

D. Distribution Expense

Edison's estimate of distribution expense exceeds PSD's estimate by approximately $9 million. The following table details PSD's and Edison's differences.

Distribution Expense Issues

Issue	Edison	PSD	Adopted
	(Dollars in Thousands)		
Trending	$61,807	$57,545	$58,306
Underground Inspection Program	3,894	888	3,894
Storm Damage	16,971	15,280	16,971

1. Trending

Excluding accounts 589, rents and 598, maintenance of miscellaneous distribution plant, Edison used 1985 recorded expenses as adjusted, to estimate test year 1988 expenses for distribution accounts. This method was utilized because of the fluctuations in recorded expenses that resulted from the curtailment of expenses in 1981 and 1982, and the completion of unbudgeted expenditures in 1984. Test year estimates for account 589, rents, were based on existing contractual agreements. For account 598, maintenance of miscellaneous distribution plant, a five-year average of the recorded expenses (1981-1985) was used to estimate the test year 1988 expenses. Edison states this is consistent with the methodology adopted in its last three general rate cases. No adjustments were made in distribution expenses for growth as Edison maintains that additional system growth will be offset by increased productivity.

PSD made adjustments for productivity and operation efficiencies in six of the distribution accounts based on trends using expenses per customer, per substation, and per mile of line of individual labor and non-labor elements within these accounts. The adjustments PSD made were designed to reflect the estimated improvements in the efficiency of operations that were recommended in 55 operational audit reports and in the productivity programs listed by Edison. As a result of PSD's trending methodologies it recommends that Edison's request be reduced by $4.3 million.

2. Account 582, Station Expenses;
Account 583, Overhead Line Expenses;
Account 586, Meter Expenses;
<u>Account 594, Maintenance Of Underground Lines</u>

As stated above, Edison used 1985 recorded expenses to estimate the test year 1988 expenses for these four accounts. There were no adjustments made for growth as Edison maintains any new productivity will serve to offset the continued growth of these expenses.

PSD also used recorded 1985 expenses to estimate test year 1988 for the non-labor expense in these accounts. However, for the labor expense, PSD based its estimates on the downward trends of the recorded years' labor expenses per customer, per substation, per overhead line mile and per underground line mile. As a result of its analysis PSD adjusted Edison's estimates downward by $3.5 million to reflect gains in productivity and operation efficiencies.

While Edison assumed that increased productivity would offset growth, PSD went beyond Edison's assumption and calculated productivity gains and increased operating efficiency based on the recorded data for these accounts. We find PSD's analysis more accurately reflects the past experience for these accounts and should be adopted.

3. Account 593, Maintenance of Overhead Lines

PSD's downward adjustment of $541,000 was based on a slightly downward trend of the recorded years (1979-1985) direct labor in function account 5252, trimming and removing trees. Edison states that the reason for the downward trend of direct labor is that the number of Edison tree trimming crews (direct labor) has been reduced and replaced with contract crews (non-labor expense). In addition, Edison argues that its test year estimate assumes no change, in constant 1985 dollars, in the level of expenses for account 593.

Since PSD's adjustment does not take into consideration the transition to contract labor and Edison's estimate does, we will adopt Edison's test year 1988 estimate for account 593.

4. Account 597, Maintenance of Meters

PSD made a downward adjustment of $220,000 based on a trend of the total account's non-labor repair costs per customer.

Edison argues that the non-labor trend was downward because the recorded expenses for 1979-1981 were high compared to 1982-1985.

Edison states that the recorded non-labor expenses were lower and relatively more level during the years 1982-1985 because all purchases of meter locking rings (non-labor expense) were assigned to the energy theft program. This changed the account to which meter locking rings were being charged from account 597 to account 587, customer installations expenses. Because PSD, unlike Edison, does not give consideration to the accounting change for meter locking rings we will adopt Edison's estimate.

5. <u>Workpapers</u>

From the sparring that took place between Edison and PSD over the data for tree trimming and meter locking rings, it appears that Edison's workpapers did not provide a through explanation of the estimates for accounts 593 and 597. Edison is reminded that a thorough justification is required for program changes and estimating methodologies proposed in NOI and application filings. If Edison does not follow this procedure in the future, it stands the risk of delaying its rate case.

6. <u>Inspection of Underground Facilities</u>

In its application Edison has included funds for an accelerated inspection program for its underground distribution network. Edison's position is that an extensive program of equipment inspection is necessary to insure the utmost reliability and safety of its distribution system and reduce equipment failure rates. On April 1, 1987, Edison implemented an expansion and acceleration of its inspection of underground facilities. This new three-year program, which is an accelerated version of the former five-year program, utilizes a sophisticated computer-based system which allows for more effective management of the program and the monitoring of results. It also includes more comprehensive inspection procedures than were previously required. In addition, this program requires a laboratory analysis of the insulating oil in all transformers and switches to determine the existence of properties such as moisture, neutrality, and interfacial tension. The new program was initiated because of the increase in underground switch failures (27.5 per year during the period 1979-1982 to 85.8 per year during the period 1983-1986).

PSD removed all of the incremental increase in labor required to perform this program in the three-year time frame on the basis that the labor would be performed by existing employees and therefore was included in the Company's recorded history for this account. PSD's witness concluded that the inclusion of an additional increment of labor expense double counted the labor requirement for this account.

PSD has also recommended that the laboratory analysis of insulating oil be completed in conjunction with the five-year program, stating that the increases in equipment failures did not appear to be an immediate threat to Edison's underground distribution system.

In response to PSD's position Edison argues that the incremental increase in labor expense represents employees who formerly worked on new business plant construction, and that the employees would be replaced with contract crews. The labor dollars included in the plant budget for those employees will now be utilized to fund additional contract crews. Consequently, there is no double counting of this required labor expense in the estimated years.

Due to the over 200% increase in switch failures, we find Edison's arguments for the need to improve the reliability of its underground distribution system convincing. In addition, PSD's claim of double counting employee labor does not take into consideration Edison's use of contract labor for capital projects. We will adopt Edison's requested funding level for its three-year underground inspection program.

7. <u>Storm Damage</u>

Edison utilized a five-year average as its estimating methodology for account 598, storm damages. In support of its estimating methodology Edison states that it was adopted in Edison's 1981, 1983, and 1985 general rate cases.

PSD used an eight-year average, 1979-1986, to consider more years of a climatic cycle. PSD's methodology resulted in a downward adjustment of $1.7 million.

PSD did not provide convincing evidence that consideration of additional years of a climatic cycle would result in a more accurate forecast over time. Consistent with Edison's prior general rate cases and other averages adopted in this decision, we will adopt a five-year average of storm damages.

E. Customer Accounts Expense

There are three areas of customer accounts expense in which Edison and PSD are not in agreement; notice of termination of residential service, uncollectibles, and postage increases.

PSD has estimated that Edison could save $850,000 in accounts 901 and 903 due to Assembly Bill (AB) 2721 (1986 Stats., Ch. 479). AB 2721 amended PU Section 779.1 to remove the requirement of physically posting a notice on the premises of a delinquent customer at least 48 hours before service is terminated. PU Section 779.1 states:

> "(b) Every corporation shall make a reasonable attempt to contact an adult person residing at the premises of the customer by telephone or personal contact at least 24 hours prior to any termination of service, except that, whenever telephone or personal contact cannot be accomplished, the corporation shall give, either by mail or in person, a notice of termination of service at least 48 hours prior to termination."

PSD has interpreted PU Section 779.1 to permit notification of service termination by means other than posting notice of termination on the customer's premises, including by mail or phone. Edison argues that PU Section 779.1 permits notification by mail only when telephone or personal contact cannot be accomplished.

At issue is whether contacting a customer by telephone or in person is less costly than posting a notice on the customer's premises. Edison does not anticipate any savings as a result of AB 2721. In support of this position Edison states a pilot program revealed no savings by telephoning service termination notifications. In addition, Edison interprets personal contact to mean notification by posting.

Since AB 2721 permits telephoning termination notices in lieu of posting, we believe PSD's position, i.e., telephoning should be less costly than posting, has merit. While Edison disputes this, it has only made vague references to a study that does not support PSD's position. Edison has not provided us with convincing evidence that its request of $4.3 million for posting notices is justified in light of AB 2721. PSD's estimated savings appear conservative when compared to Edison's request and we will adopt them as reasonable.

The second adjustment which PSD made involves the calculation of the uncollectible rate. PSD used a two-step approach. First, the uncollectible rate was calculated using the last three years' recorded data, adjusted for inter-utility information exchange program (Enercom) savings in 1986. PSD claims that the three-year average is appropriate, because it reflects Edison's significantly improved collection practices, including Edison's new credit scoring system and its recent success at maximizing collections from customers in bankruptcy proceedings. Next, PSD adjusted the calculated uncollectible rate by factoring in the estimated savings from Edison's participation in the Enercom system. PSD estimated that this system, which produced savings of $225,000 in 1986, would achieve $775,000 in savings in 1988 if expanded to other utilities. For this reason, PSD recommends that the Commission give the strongest encouragement to other large investor-owned and municipal utilities to participate in the Enercom program.

With the adjustment for Enercom PSD estimated that Edison's uncollectible rate for the test year would be .203%, a figure that PSD believes compares favorably to the recorded 1986 value of .204%. The revenue requirement impact of this adjustment is $295,000, based on PSD's estimate of 1988 base rate revenues.

Edison agrees with PSD's use of a three-year average of uncollectibles adjusted for recorded Enercom savings, but does not agree with PSD's projected increase in Enercom savings. Edison believes there is no basis for PSD's assumption that Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCal), and/or Los Angeles Department of Water and Power (LADWP) will join Enercom. In support of this assertion Edison states that the PSD's witness indicated that LADWP management was opposed to an Enercom concept, PG&E was not contacted, and SoCal had not reached agreement with Enercom. Finally, Edison argues that only 10% of the savings realized in 1986 was derived by locating former Edison customers outside of its own service territory.

Enercom is an independent company that maintains information on accounts determined to be uncollectible and matches this data to turn-on applications on a weekly basis. Enercom retains the turn-on information in their data base for a period of six months and retains the information on uncollectible accounts for a period of three years. The cost of Edison's participation in Enercom is a flat monthly fee of $3,050.

We consider Enercom to be an important tool in minimizing the amount of uncollectibles utilities experience. In Edison's case Enercom is cost-effective by a factor in excess of six to one. With increased participation by utilities, both investor-owned and municipal, the cost-effectiveness of Enercom would increase. We expect the utilities we regulate to seriously consider participating in Enercom and they should anticipate that their progress will be reviewed in future general rate cases.

Because of the uncertainty that other major utilities will participate in Enercom during the test year, we will only reflect Edison's recorded Enercom savings for 1986 in our adopted uncollectible rate. We will adopt an uncollectible rate of .214% based on PSD's three-year average of uncollectibles and Enercom savings of $225,000. Since this is a change from Edison's last adopted uncollectible rate, Edison's annual energy rate and ECAC should reflect the uncollectible rate of .214% as of January 1, 1988.

The final area of disagreement between PSD and Edison concerns postage increases. Edison proposes that postage increases occurring during the test year be noticed by advice filing during the test year and credited to the electric revenue adjustment mechanism (ERAM) balancing account. PSD recommends that postage increases occurring during the test year should only be reflected in Edison's attrition filings.

Consistent with prior general rate case decisions in which prospective increases due to governmental actions were at issue, we will not consider increases during the test year for items which are minor in nature. However, we will allow Edison to reflect postage increases in its attrition filings.

F. Administrative and General (A&G) Expense

Edison's estimate of A&G expense exceeds PSD's estimate by $26.4 million, excluding franchise taxes, RD&D, and load metering expense. PSD developed its adjustment by making specific recommendations after analyzing Edison's requested budget and by placing a ceiling on the amount of increase Edison should be authorized. The following table details the dollar amounts at issue:

Administrative and General Expense Issues

Issue	Edison	PSD	Adopted
	(Dollars in Thousands)		
School Representative Activities	$ 391	$ 54	$ N/A
Customer Service Activities	1,062	924	N/A
Load Metering and Customer Survey	725	0	*
Executive Incentive Compensation	1,635	818	N/A
Outside Services	4,056	4,056	N/A
General Advertising	1,105	0	N/A
Corporate Communications-Annual Report	456	100	N/A
Director's Pension Plan	751	0	N/A
Annual Report Mailing	80	50	N/A
Directors and Officers Insurance	4,864	2,432	4,378
Group Life Insurance	938	801	801
Other Insurance	12,182	9,938	10,964
Medical	66,688	61,788	62,418
Miscellaneous Benefits	(28,434)	(29,497)	N/A
RD&D	24,721	21,799	24,416
A&G Transferred	(26,705)	(26,313)	N/A
A&G Ceiling Adjustment	0	(13,627)	(5,030)

* $725,000 included in customer service and information expenses

Edison utilized a modified budget-based methodology to estimate its level of A&G expense, which it claims is consistent with the Commission's directives in Edison's 1983 test year general rate case decision. The modified budgetary estimating methodology uses 1985 recorded expenses as an estimating base from which increases and decreases in activities are identified for the years 1986-1988.

PSD's recommendations adjust Edison's requested A&G expense in two ways. First, specific adjustments totaling $17.6 million are made. Second, PSD recommends a 10% ceiling based on customer growth be applied to Edison's total increase in A&G expense from 1985-1988. This results in an additional reduction of $13.6 million.

A&G expense is an extremely difficult area in which to control costs. Numerous items from paper clips to the president's salary to medical and insurance premiums are recorded in A&G accounts. Because of this variety in expense categories and their sometimes volatile increases, A&G has not lent itself to any one estimating methodology. In past decisions we have adopted A&G expense estimates using trends, budgets, recorded expenses, and growth in employees, customers, and sales.

Again, we find ourselves in the dilemma of determining a reasonable level of A&G expense. This task is particularly difficult due to the inability to control certain items, such as pension, medical and insurance costs, which together comprise nearly 50% of all A&G expense. Since A&G expense can be divided into costs over which Edison has control and those over which it does not, we will develop our estimate on this basis.

1. <u>Controllable Costs</u>

First, we will address those items over which Edison has control. For this decision we will exclude insurance (accounts 924 & 925 and group life insurance), pension, dental, vision, and medical plan costs, F/MBE program costs, franchise taxes, and RD&D from the items over which Edison has control. The remaining items mainly consist of salaries and office supplies for which Edison is requesting a 11% increase in constant dollars over recorded 1985. For this same period Edison's customer growth is about 8%. Edison's showing for these items is vague with only general references to various program changes and hardly it provides adequate justification for its request.

Edison carries the burden of proving that its request is reasonable. This is especially true for A&G accounts which are a catch all for expenses which have no specific identification. As stated above, Edison has not provided adequate justification for its requested increase. Due to this deficiency in Edison's presentation we will limit the increase for the A&G items which are within Edison's control to 8%, the expected customer growth from 1985 to 1988. Since these items are impacted by customer growth, we believe this is a reasonable adjustment. This results in a $5.0 million reduction in Edison's request.

Our adopted expense modifies PSD's second recommendation to apply only to the A&G items over which Edison has control and limits the increase to the percentage change in customer growth for the 1985-1988 period. This approach does not endorse any specific programs or activities proposed by Edison, the adjustments made by PSD, or Edison's 1985 expense level. It will be left to Edison to manage A&G expense within its budget. However, in its next general rate application we expect Edison, regardless of its estimating methodology, to provide a detailed justification for each A&G account. This should include a description of each A&G program or activity together with five years of recorded data and an explanation of all significant changes in the recorded and projected data.

Excluding RD&D, which is discussed in the section on RD&D, the remaining A&G expense issues are addressed below.

2. <u>Uncontrollable Costs</u>

a. <u>Insurance</u>

PSD recommends that Edison's requested funding of insurance premiums for property, general liability, directors and officers, and group life be reduced by $4.8 million. PSD's adjustment assumes that insurance premiums generally are in decline after a period of precipitous increases. This assumption was based on a review of literature related to the insurance industry and discussions with insurance professionals, including several brokers and a risk manager of a large U.S. corporation. Additionally, PSD observed that Edison's insurance premiums, having increased recently preceded by a decrease in the 1983-1984 period, generally follow market trends. PSD asserts that the combination of the softening of the insurance market and Edison's power in that market as a significant consumer present opportunities for cost savings.

Besides the general changes in the insurance industry, PSD believes that the Fair Responsibility Act of 1986 (Civil Code Sections 1431.1-1431.5) and enactment of the Risk Retention Amendments of 1986 (P.L. 99-563, 100 Stats. 3170) should exert a downward pressure on general liability premiums. Accordingly, PSD reduced Edison's estimates for certain insurance premiums by 20% and 15%. Finally, PSD recommends a $137,000 reduction in Edison's estimated group life insurance premium due to the lack of billed invoices and a split of directors and officers insurance premiums between shareholders and ratepayers.

PSD's proposal that directors and officers insurance premiums should be split between shareholders and ratepayers is premised on a sharing of the benefits. Insurance covering directors and officers of a corporation is designed to protect against shareholder derivative law suits. In the event of a successful shareholder derivative law suit, the insurance policy provides funds to make the shareholders whole for damages caused by wrongful or negligent acts of corporate directors or officers. Ratepayers also derive benefit from this type of insurance. In the absence of such insurance, there could be a legitimate claim against an officer or director resulting in a substantial damage award that could increase the cost of capital.

Edison believes that PSD's perception of a softening of the insurance market is based on a limited analysis and that property and general liability insurance pose unique risks. In support of its position Edison presents the following arguments:

1. Growth in the size of Edison's assets, and the increased replacement value of those assets due to inflation, will prevent property insurance premiums from declining.

2. Edison's boiler and machinery coverage is a specialized part of property insurance coverage and does not follow the general insurance market.

3. Edison's earthquake coverage has been difficult to obtain at any price.

4. Involvement in a number of alternative insurance companies insulates Edison from the ups and downs of the commercial insurance market.

5. Dramatic increases in litigation and changes in the way that insurance policies are interpreted by courts have caused insurers to pay for losses that they never intended to cover.

With respect to directors and officers insurance, Edison believes it is a normal cost of doing business, which not only covers the directors and officers but also the corporation. Edison argues that directors and officers coverage provides for defense costs without regard to the merits of the law suit and is necessary to attract and maintain well-qualified and able directors and officers.

Due to the increase of derivative law suits in recent years, directors and officers insurance has become commonplace in the corporate world. Without this protection the risks of serving as a director or officer would outweigh the rewards. A well managed and efficient utility is predicated upon having qualified and capable directors and officers and this type of insurance is critical in obtaining and maintaining these individuals. For this reason PSD's recommendation would impose an unwarranted penalty on Edison's shareholders and will not be adopted.

In estimating Edison's insurance premiums we have placed a heavy emphasis on PSD's arguments that there is a softening of the insurance market and that Edison's insurance premiums have generally followed market trends. We also consider Edison's claims concerning the difficulty in obtaining earthquake insurance and its involvement in alternative insurance companies to insulate it from market surges persuasive. After weighting these factors we have concluded that PSD's proposed reductions of 20% and 15% are too drastic. Instead, we will assume that comprehensive liability, directors and officers, and property insurance premiums will be 10% lower than Edison's projections. Since Edison has not provided PSD with the necessary invoices to justify its estimated cost of group life insurance we will adopt PSD's estimate. These combined adjustments result in a $1.8 million reduction to Edison's estimated 1988 premiums. Edison and PSD have agreed to the estimated premiums for crime, nuclear property, nuclear replacement generation, and nuclear liability insurance. These estimates appear reasonable and will not be adjusted.

b. <u>Medical Costs</u>

The method used by Edison to estimate outside provider medical costs took into consideration three factors: (1) overall medical cost escalation factors as provided by the actuary, (2) growth in employee participation, and (3) the ratio of dependents to employees. Edison derived its estimate from 1985 recorded data using the three factors above.

PSD recommends a $4.9 million reduction in Edison's estimated outside provider medical costs. PSD's adjustment is the result of using 1986 recorded data, a lower ratio of dependents to total participants, and no growth in the number of participants.

We will adopt PSD's use of 1986 recorded data adjusted for the increase in employees from the 1986-1988 period. This approach assumes that the existing relationship of total employees to employees participating in the plan remains constant through the test year. We believe this is a reasonable assumption in the absence of data in record to support Edison's or PSD's position. Our adopted estimate of outside provider medical costs is $4.3 million lower than Edison's request.

c. Load Metering and Customer Survey Expense

Consistent with our discussion in the customer service and information section we will move Edison's load metering and customer survey expense to account 908.

d. Franchise Taxes

Edison and PSD are in agreement on the use of a franchise tax rate of 0.73%. Since this is a change from Edison's last adopted franchise tax rate, Edison's annual energy rate and ECAC should reflect the franchise tax rate of 0.73% as of January 1, 1988.

G. Taxes

With the exception of the Superfund Tax, Edison, PSD, and FEA are in agreement on the methodology to be use for calculating payroll, ad valorem, and income taxes. Differences in tax estimates are due to differences in payroll, plant, and expense estimates.

The amount of the Superfund Tax is not at issue, only Edison's classification which treats it as a deductible tax in the computation of income taxes. Edison states that its interpretation and of the Superfund Tax is supported by the opinions of tax experts within the utility industry. PSD's classification treats the new Superfund Tax as a nondeductible addition to to Federal income taxes. We will adopt Edison's position which results in a lower estimate of State and Federal income taxes.

While no longer in dispute, FEA raised the issue of the appropriate ad valorem tax rate to be used in determining Arizona property taxes for Palo Verde. Edison and FEA agreed to use the rate of 2.95%.

Besides the Superfund Tax treatment, I.86-11-019 is considering the effect of the Federal Tax Reform Act of 1986 on regulated utilities. Edison and PSD have endeavored to incorporate the provisions of the Tax Reform Act of 1986 in their showings. We will reflect those provisions in this decision. If additional tax changes are required, Edison, should follow the direction set out in our decision in I.86-11-019.

H. Plant-in-Service

For this proceeding PSD devised an approach for estimating plant-in-service that compares prior utility estimates with actual recorded weighted average plant-in-service. Using this methodology PSD found that over a seven-year period, for which data was available, Edison had overestimated its weighted average plant-in-service by an average of 2.28%. PSD's application of this factor to Edison's test year estimates resulted in a difference of $223.9 million in test year plant.

Edison argues that PSD agreed with Edison's beginning of year 1987 plant-in-service estimate and did not recommend adjusting Edison's capital projects for 1987 and 1988. Not only does Edison believe that it is inconsistent to adjust its weighted average plant without adjusting plant-in-service or plant additions, it also points out that PSD's methodology could result in plant estimates that are lower than recorded.

In contrast, Edison developed its 1988 plant-in-service estimate by adding forecasted plant additions to 1985 recorded plant-in-service. Estimated plant additions for the years 1986-1988 were obtained from Edison's five-year plant and work element budget and forecast. Edison's plant additions are categorized by class of plant and by month and year of operation. From this data month-by-month plant balances by class of plant, including construction overheads and plant retirements, were calculated for the forecast period.

The testimony of PSD's witness reflects little preparation and a lack of understanding of how plant estimates are developed for ratemaking. First, PSD's witness was unable to provide basic information concerning estimated plant additions for 1987 and 1988. Next, PSD's witness developed an adjustment factor from an analysis of recorded versus budgeted plant. Finally, this adjustment factor was applied to Edison's estimated total plant which reduced Edison's net plant additions by 44% and resulted in no recovery for .7% of recorded plant.

We find PSD's approach of adjusting total plant based on a factor developed from using budgeted versus recorded plant inappropriate. Even if PSD's adjustment was corrected for this flaw, we find its methodology a poor substitute for a detailed analysis of Edison's estimated construction projects taking into consideration their need, estimated cost, and expected operation date. We consider Edison's detailed estimating methodology reasonable and will adopt its plant-in-service estimates for test year 1988.

I. Depreciation

During the September update hearings Edison revised its average service lives and net salvage amounts for transmission and distribution classes of plant. This change resulted in lower depreciation rates and decreased Edison's depreciation expense by $69.3 million. PSD has agreed to Edison's revised depreciation rates. The only difference between Edison's and PSD's estimates of depreciation expense and reserve is due to differing plant estimates. We will adopt Edison's revised depeciation rates for use in this decision.

J. Plant Held for Future Use (PHFU)

PHFU includes land and plant related items that have been acquired by Edison for use in the future. In its application Edison requested that it be allowed to earn a return on $128.2 million in PHFU for test year 1988. Since its application was filed, Edison reevaluated its PHFU estimate in light of the PHFU guidelines it and PSD developed and agreed to reduce the amount by $7.0 million.

During the course of the its audit, PSD questioned Edison's specific plans for using 56 parcels of land in PHFU. PSD claims that under current plans, the average time that these parcels would remain in the PHFU account is 27 years and as of January 1, 1987 they have averaged over 16 years in PHFU. Additionally, PSD points out that the carrying charges for the ratepayers (18.10%, return times net to gross) is substantially greater than for Edison (10.77%, return on rate base). Faced with this circumstance, PSD recommends that all of the 56 parcels be excluded from rate base for the test period, an adjustment of $20.4 million. Finally, PSD identified a parcel valued at $520,000 that was double counted in Edison's application.

In response to a request by ALJ Ferraro, PSD propounded a series of guidelines to govern the length of time that items could be retained in PHFU. The guidelines, attached as Appendix B, provide for the following:

1. Distribution substations and transmission plant (not related to new power plants) could be held in PHFU and not placed in Edison's plant expenditure review committee (PERC) budget for five years. If by the end of five years, the property has not been included in the PERC budget, it will be removed from PHFU until it is included in a future PERC budget.

2. Generation and transmission plant (related to new power plants) can be held in PHFU and not be included it the PERC budget for ten years. If at the end of ten years, the property has not been included in the PERC budget, it will be removed until it is included in a future PERC budget.

While PSD states that the guidelines may be valuable for the future, implementing them on a prospective basis will not remedy the injustice that ratepayers have endured by absorbing significant carrying costs over past years.

Edison worked with PSD in developing the guidelines and believes that they should be adopted prospectively. Edison states that the guidelines give guidance, are fair and workable, and benefit Edison and its ratepayers. Finally, Edison points out that the guidelines give Edison appropriate flexibility, provide reasonable compensation, and give ratepayers protection from paying for property that may ultimately end up not being needed.

Adoption of the guidelines prospectively results in a $7.0 million reduction from the amount Edison originally requested be included in PHFU. Edison is in agreement with this reduction, but is opposed to PSD's recommended exclusion of $20.4 million from PHFU. Edison argues that PSD's recommendation is unfair because the needs for the property were not considered and it was based solely on PSD's judgement that the property has been in PHFU too long.

PHFU is an area in which we do not have any specific criteria for judging the reasonableness of a utility's property acquisition policies. Because of this, utilities do not have a strong incentive to closely monitor their procedures for acquiring and maintaining PHFU. ALJ Ferraro directed PSD and Edison to work together to develop guidelines which could be used to judge the reasonableness of utility expenditures on PHFU. As a result, PSD and Edison developed guidelines and agreed to their use in the future. We find these guidelines reasonable and will adopt them for use in this and Edison's future general rate cases. In addition, we will direct our Evaluation and Compliance Division to notify the energy utilities under our jurisdiction that we expect to adopt similar guidelines in their next general rate case.

Although PSD and Edison are in agreement that the guidelines should be used in future general rate cases, they are in disagreement over their use in this proceeding. PSD's auditors are concerned over the length of time that ratepayers have paid high carrying charges on 56 parcels in PHFU, while Edison has identified a specific use for most of these properties and argues that it would be unfair to apply the guidelines retroactively.

Because Edison has identified a specific use for most of the properties at issue, we will not adopt PSD's recommendation in its entirety. However, starting January 1, 1989 we will apply the adopted guidelines as if they were effective prior to the acquisition date of all items in PHFU. This will result in a reduction of $16.2 million from Edison's original request for 1989. For test year 1988 we will reduce Edison's original request by $7.5 million. This represents $7.0 million, Edison's agreed reduction, and $520,000, PSD's double counting adjustment.

By delaying full implementation of the guidelines Edison should have ample opportunity to manage its PHFU account to the level adopted in this decision. Edison can accomplish this by delaying future purchases, selling property not needed in the near future, placing property in plant-in-service as it becomes used and useful, or by transferring property to nonutility property. We believe, by providing ratepayers with lower carrying charges now and in the future and shareholders with the opportunity to adjust to this change, the interests of ratepayers and shareholders are fairly balanced.

K. Working Cash Allowance

With one exception Edison and PSD are in agreement on the methodology for calculating the allowance for working cash. The only remaining issue concerns the weight that should be given to the lag in the State income tax deduction used in determining Federal income taxes. In its estimate of working cash allowance Edison reflects the fact that the previous year's rather than the current year's State income taxes are used as a deduction for calculating corporate Federal income taxes. Consistent with prior

Commission decisions, PSD recommends that no consideration be given to this issue in estimating working cash allowance.

This issue was first raised in PG&E's general rate case A.85-12-050. By D.86-12-095 in that proceeding we ordered workshops to be conducted which would include other energy utilities. Edison has participated in those workshops, but at this time there has not been a final resolution of the matter. Accordingly, we will adopt PSD's recommendation, but allow Edison's general rate case to remain open until this issue is finally resolved. Edison will be allowed to record in a memorandum account the difference between the adopted revenues and those Edison's proposed working cash methodology would yield. The difference in revenues recorded in the memorandum account should accrue interest at the energy cost adjustment clause (ECAC) balancing account rate.

L. Attrition

Edison and PSD are in agreement on the method of calculating attrition. Additionally, both recommend that the 1989 ERAM base level should be increased by $9.8 million to reflect a change in jurisdictional allocation due to a decrease in FERC jurisdictional sales. Edison and PSD recommend no change in the jurisdictional allocation factors for 1990. Finally, the revenue requirement associated with Edison's optional time of use meter plan will be reflected in calculating attrition for 1989 and 1990. This item is discussed in more detail in the section on rate design.

V. Major Issues

A. Cost of Capital

In recent general rate cases for the large electric utilities, we have indicated that a utility should be authorized a return on common equity (ROE) that is commensurate with market returns on investments having corresponding risks. We also have repeatedly stated that there are three considerations which we rely upon to implement this objective:

1. Cost of capital varies in the same direction as changes in the general level of inflation and interest rates.

2. Market cost of equity capital reflects risks, such as the exposure of a utility's earnings to variability in fuel costs, sales levels, as well as uncertainties regarding the cost of prior capital investments.

3. The application and interpretation of financial models may not accurately reflect all of the intricacies of the financial market.

In evaluating the proposals before us from Edison, PSD, and FEA we will place heavy emphasis on these principles. Each parties' position on the various cost of capital issues is summarized in the table below followed by a detailed discussion of the issues.

Cost of Capital Recommendations for Test Year 1988

PSD

Component	Capitalization Ratio	Cost Factor	Weighted Cost
Long-term Debt	47%	9.26%	4.35%
Preferred Stock	7	7.80	.55
Common Equity	46	12.00*	5.52
Total	100%		10.42%

* Midpoint of Range.

Edison

Component	Capitalization Ratio	Cost Factor	Weighted Cost
Long-term Debt	47%	9.26%	4.35%
Preferred Stock	7	7.88	.55
Common Equity	46	13.75	6.33
Total	100%		11.23%

FEA

Component	Capitalization Ratio	Cost Factor	Weighted Cost
Long-term Debt	47%	9.17%	4.31%
Preferred Stock	6	7.80	.47
Common Equity	47	12.55	5.90
Total	100%		10.68%

Before moving to the cost of capital issues in this proceeding, it should be noted that this decision will only address Edison's cost of capital for test year 1988. To more accurately reflect changes between rate cases, we expect utilities, as discussed in D.85-12-076, to address return on equity in their annual attrition filings. In addition, we wish to make it clear that the utilities are also expected to reflect in these filings any changes which would affect their last adopted capital structure. Finally, Edison's MAAC and IMAAC should be adjusted as of January 1, 1988 to reflect the adopted ROE in this decision.

1. Capital Structure

Edison and PSD made specific recommendations on capital structure, while FEA reviewed the estimates and adopted PSD's original capital structure. The specific recommendations are shown in the table below.

Comparison of Edison and PSD Capital Structures

	Edison	PSD*		
	1988-1990	1988	1989	1990
Long-Term Debt	47%	47%	46%	45%
Preferred Stock	7%	6%	6%	5%
Common Equity	46%	47%	48%	50%

* Table Reflects PSD's Original Position. PSD Adopted Edison's Revised Capital Structure After the September Update Hearings.

Edison's recommendation is based on a target capital structure which was designed to help maintain its financial integrity while minimizing costs to ratepayers. Although Edison originally forecasted that its common equity ratio would increase to 48% or more during the 1988-1990 period, in the September update hearings it lowered its forecast to 46%. Edison's change in common equity percent reduced its base rate revenue increase by $18 million and its total revenues including MAAC by approximately $25 million. According to Edison's chief financial officer the reasons for this revision are: (1) to mitigate uneconomic bypass and (2) facilitate the move to marginal cost-based rates.

PSD originally proposed a separate capital structure for each year of the test period based on Edison's financing plan. In support of that recommendation PSD argued that: (1) it accurately reflects Edison's financing year by year rather than Edison's front loading the expensive components of capital costs and (2) if the capital structure requires adjustment, it can be made in the context of the attrition rate adjustment mechanism. After the September update hearings, PSD submitted Exhibit 245 in which it adopted Edison's revised capital structure.

In light of Edison's updated testimony we have an opportunity to provide ratepayers with lower rates without jeopardizing Edison's financial standing. We will adopt Edison's revised capital structure for test year 1988.

2. Long-Term Debt

Edison, PSD, and FEA made recommendations regarding the cost of new debt and the resulting embedded cost of debt for the 1988-1990 period. Their estimates of the incremental cost of long-term debt are set forth in the following table.

Incremental Cost of Long-Term Debt

	1987	1988	1989	1990
Edison	10.00%	10.00%	10.00%	10.00%
PSD	9.49%	10.37%	9.82%	9.60%
FEA	9.63%	10.94%	12.06%	11.06%

PSD relied on the DRI September 1987 forecast of interest rates for AA utility bonds, FEA adopted the Wharton Econometrics forecast, and Edison reviewed current forecasts and used judgement to develop its recommendation.

FEA finds fault with Edison's judgement because Edison lowered its requested return on common equity from its original application to reflect lower interest rates, but retained its estimated cost of new debt. PSD argues that neither PSD or Edison has the resources to develop and maintain forecasting models for interest rates; both must rely upon forecasting services with access to vast amounts of data and an acknowledged expertise in the field.

While there are many areas in developing estimates for the test year to which judgement must be applied, we find Edison's approach unnecessary in light of the availability of acknowledged expert forecasting services. Since DRI forecasts are used to develop the non-labor escalation factors in this decision and in the attrition rate adjustment mechanism, we will use PSD's estimated cost of long-term debt.

3. Tax-Exempt Financing

A portion of Edison's debt is represented by variable-rate tax-exempt pollution control bonds. Based on their historical relationship with Moody's double-A utility bond yields, Edison estimates an interest rate of 6.4% for its tax-exempt issues in 1988. PSD derived its estimated interest rate of 5.38% by using the historical relationship between tax-exempt issues and the prime rate. PSD slightly increased its forecasted interest rate to recognize the decline in marginal tax rates due to the Tax Reform Act of 1986.

Both of these approaches appear to be flawed. PSD criticizes Edison's forecasting model for yielding a poor correlation between interest rates for tax-exempt bonds and double-A utility bonds. In response, Edison states that the interest rate for its tax-exempt bonds is no longer based on the prime interest rate.

The only reasonable guide we have to judge the results of these recommendations is a comparison with recent recorded data. PSD's prior forecast for 1987 was only 0.1% higher than recorded data for the first quarter of 1987. Since there was only a slight difference between PSD's forecast and recorded data, we will adopt PSD's estimated cost of variable tax-exempt bonds. However, we are not convinced that PSD's methodology will always yield the best results and instruct PSD to address Edison's concerns before recommending its use in future proceedings.

4. Preferred Stock

Edison issues two types of preferred stock: sinking fund and perpetual. Sinking fund securities have a fixed-term and are essentially equivalent to debt instruments, because they are issued for a specific term at a fixed dividend rate. Perpetual securities are similar to common equity in that they do not have a sinking fund provision or a specific term.

The issue which PSD raises is Edison's proposed recovery of issuance costs on perpetual securities which have been called. Edison proposes to recover these costs by increasing the embedded cost of preferred stock. This is consistent with the recovery of unamortized issuance costs when sinking fund preferred stock is called. PSD takes the position that perpetual and common equity stock are similar and should be treated in a like manner. Since issuance costs for common equity stock are not recovered from ratepayers, PSD recommends that issuance costs for perpetual stock not be recovered from ratepayers.

In Edison's reply brief it points out that San Diego Gas & Electric Company (SDG&E) in D.87-07-079 was authorized to recover the unamortized issuance costs associated with perpetual securities. Consistent with D.87-07-079 we will allow Edison to recover the unamortized issuance costs for the perpetual securities it requested.

Edison's request for recovery of issuance costs only increases the cost of preferred stock by 8 basis points. Due to rounding, this small increase actually has no impact in the overall rate of return and does not affect the revenue requirement for test year 1988.

5. Common Equity

Of all the issues in the cost of capital area, ROE, due to the dollars involved, was the most heavily contested. A summary of the various positions of the parties is shown in the following table.

Summary of ROE Recommendations

Party	ROE
Edison	13.75%
PSD	11.75%-12.25%
FEA	12.55%

While all three parties submitted testimony showing the results of various financial models as the starting point for establishing ROE, they cautioned that the model results must be tempered by judgment. Risk premium and discounted cash flow (DCF) models were presented by all parties. Additionally, PSD developed a capital asset pricing model and FEA made an analysis of the earnings of comparable utilities. The following table summarizes the results of these models.

ROE Model Results

Party	Model	ROE
Edison	Risk Premium	13.5%-15.0%
	DCF	12.4%-14.5%
PSD	Risk Premium	13.5%-18.4%
	DCF	11.5%-12.5%
	Capital Asset Pricing	11.7%-12.6%
FEA	Risk Premium	12.3%-14.0%
	DCF	11.5%-13.0
	Comparable Earnings	13.1%

Because these models are only used to establish a range for ROE, we will not repeat the detailed descriptions of each model contained in the parties' exhibits. Additionally, the parties have put forth arguments in support of their analyses and criticizing the input assumptions used by others. As can be seen from the above table these models yield a wide range of results depending upon the choice of various input assumptions. Our review of these arguments indicates that they do not significantly alter the model results shown above. We believe these model results provide a reasonable range from which to choose an appropriate ROE and will be used as a guide in selecting Edison's ROE. In the final analysis it is the application of our judgement that is crucial, not the accuracy of a particular model.

In applying judgement to the results of its models, Edison, as detailed by the testimony of its chief financial officer, John Bryson, identified the major items which justify its proposed ROE. These are: maintaining its financial integrity and the increased risk associated with regulatory changes, competition, system operations, and uncertain economic conditions.

Edison argues that it is in the best interest of both its customers and investors to maintain its financial integrity and thus retain access to the lowest cost funds available during all market conditions. This, Edison claims, requires a ROE of 13.75% in order to keep its double-A credit rating.

As further justification for its proposed ROE, Edison states that in recent decisions, two broad categories of risk allocation have been reflected: (1) retroactive imposition of risks to the utility based on results of prior conduct, and (2) prospective allocation of risk associated with uncertain future events. Edison believes that investors perceive these as new risks and demand a higher return.

Second, Edison identifies competition from third-parties and self-generators as a new risk in the eyes of investors. This risk occurs because these companies are not subject to traditional utility constraints and obligations, but are allowed to compete with utilities for customers and new resources.

Third, Edison argues that it no longer has sole responsibility and control over its sources of energy. This results from Edison's increased reliance on third-party generation and purchases from distant utilities. In addition, a significant amount of Edison's generating resources are nuclear which can be adversely affected by events wholly outside Edison's facilities, service area, or control.

Finally, Edison points to the volatility in the economy, especially the uncertainty in the prospective levels of inflation, interest rates and oil prices.

PSD counters by stating that the last decade has seen the implementation or refinement of a variety of rate mechanisms and policies, all of which have generally served to diminish the risks attendant to operating an electric utility. These include: ECAC which protects the utility from the variability of fuel costs; ERAM which insulates the utility from the vagaries of electric system sales; the attrition rate adjustment which provides opportunities for base rate adjustments in the years between general rate cases; MAAC which provides rate recognition for major capital projects; and the rate case plan which insures timely processing of utility rate applications.

In addition, PSD argues that Edison's recent financial performance indicates it is a strong company, with a risk profile that is relatively low. To support this claim PSD points to the following Edison financial indicators:

1. 1986 was the sixth consecutive year of record earnings.

2. Allowance for funds used during construction has declined as a percentage of earnings for five consecutive years.

3. In 1986 80% of capital needs were provided through internal generation of funds, the highest level in 25 years.

4. Earnings have averaged over 30 basis points in excess of the authorized return on equity during the last five years.

5. Declared dividends on common shares have outpaced the consumer price index over the last five years.

6. Common shareholders have realized an average annual return of 28.5% over the last five years.

7. Common shares were selling at a 54% premium above book value at the end of 1986.

8. A double-A bond rating has been maintained for more than a decade.

Besides these healthy financial indicators, PSD points out that Edison no longer faces uncertainty with regard to the final disposition of SONGS and, through subsidiaries, has made investments in the area of QF energy production. Finally, PSD believes that today's market reflects a perception by investors that risks are lower than in the past and proposes that Edison receive a rate of return at the lower end of the recommended ranges.

As we stated at the outset, our ROE determination is largely influenced by changes in and the level of inflation and interest rates in combination with the results of various financial models. Other factors, such as the financial condition of the utility and changes in regulatory and business risks, are considered, but typically have a lesser impact on the final ROE.

In Edison's last general rate case, for test year 1985, we authorized a 16% ROE. Since that decision, there has been a considerable reduction in interest and inflation rates. These lower and more stable factors support a significant reduction in the authorized return. Some of this reduction has already been reflected by the negotiated agreement between Edison and PSD which resulted in authorized returns of 14.6% for 1986 and 13.9% for 1987.

All parties, including Edison, recognize that further reductions below the currently authorized ROE of 13.9% are justified. The only question is the magnitude of the reduction. Today's economic indicators paint a much rosier picture than those of three years ago. Interest rates for long-term debt are estimated to be in the 10% range, inflation is projected around 4%, and Edison has just had the best financial performance in its history. This is a considerable improvement over test year 1985 in which long-term interest rates were expected to be 13%, inflation estimated around 6%, and Edison was facing a major reasonableness review of SONGS 2 and 3.

Edison's showing places a heavy emphasis on maintaining its financial integrity. While we feel this is an important goal for Edison and its ratepayers, it is not the Commission's charge to insure Edison achieves this goal. Our objective is to authorize a ROE commensurate with market returns on investments having corresponding risks. In this way we provide Edison with the opportunity to maintain its financial integrity through effective management.

Finally, Edison claims that it faces substantial risk due to recent regulatory changes, system operation changes, and uncertain economic conditions. We agree with Edison that all of these are factors considered by investors and we will give recognition in our adopted ROE to certain changes in risk. However, three years ago there also was uncertainty in the economy and Edison's nuclear operations and purchases from distant utilities were essentially as they are today. No change from the treatment provided these items in Edison's last general rate case appears warranted at this time.

In summary, we believe that the low and stable levels of interest and inflation rates coupled with the financial models presented by the parties all point toward a significant reduction in Edison's authorized ROE. After taking into consideration all of the evidence relative to market conditions, Edison's financial health and exposure to risk, and the testimony on financial models, we conclude that a ROE of 12.75% is just and reasonable for test year 1988. Our adopted ROE produces an overall rate of return of

10.77% which we feel is sufficient to attract and compensate investors.

As discussed previously our adopted ROE is only for test year 1988. For subsequent years it will be subject to review in Edison's attrition filings. The following table details our adopted cost of capital.

Adopted Cost of Capital

	Contribution Ratio	Cost Factor	Weighted Cost
Low-term Debt	47%	9.26%	4.35%
Preferred Stock	7	7.88	.55
Common Equity	46	12.75	5.87
Total	100%		10.77%

B. Nuclear Fuel and Coal Fuel Inventory Financing

Edison proposes to phase-out its nuclear fuel lease for SONGS and include all nuclear fuel and coal inventory in rate base. PSD recommends that the carrying costs on all nuclear fuel and coal inventory be calculated using the short-term debt rate in ECAC.

1. Nuclear Fuel

In 1974 Edison entered into a lease arrangement to procure its nuclear fuel requirements for SONGS. This lease arrangement permitted Edison to finance its nuclear fuel at favorable short-term rates which, because of the lease structure, was not reflected on the company's balance sheet. Due to an accounting change made by the Financial Accounting Standards Board, Edison, beginning in 1987, must reflect capital leases on its balance sheet. Accordingly, Edison plans to purchase its nuclear fuel and phase-out the nuclear lease over time. In its application Edison has requested rate base treatment for a portion of the nuclear fuel it will own.

PSD sees the issue differently and proposes that SONGS nuclear fuel carrying costs continue to be recovered through ECAC, based on short-term rates. In addition, PSD recommends that Palo Verde nuclear fuel carrying costs be recovered in a like manner through ECAC. PSD believes this is appropriate for the following reasons:

1. The Commission has pursued a policy in recent years of removing fuel inventory assets from rate base and allowing the recovery of carrying costs at short-term rates through ECAC. There is no reason to make an exception for nuclear fuel.

2. The Commission recently issued D.87-05-059, authorizing Edison to guarantee short- and intermediate-term debt instruments issued by one of its subsidiaries for the express purpose of financing nuclear fuel.

3. Edison is not required to terminate its lease and there is no reason why ratepayers should pay higher carrying costs because of a change in how capital leases are treated in Edison's financial statements.

PSD estimates that the increased cost for full recognition in rate base of nuclear fuel, including Palo Verde, would be over $48 million and even with Edison's phased-in approach the increased cost would be over $8.5 million in test year 1988.

Edison argues that nuclear fuel should not be afforded the same treatment as other fuel because of its four to six year life and unique characteristics. Edison states that nuclear fuel has a much longer life than other fuels, cannot be used (burned) for up to two years, goes through extensive processing before it can be loaded into a plant, and is plant specific. Edison believes financing nuclear fuel with permanent capital as reflected in its imbedded-cost of debt appropriately matches asset and liability life and risk.

Since it entered into the nuclear leasing arrangement, Edison states that accounting standards, bond rating agencies, and investor perceptions toward off-balance sheet financings have become more stringent. As a result Edison believes that equity support is needed for nuclear fuel and proposes to achieve this through rate base treatment.

To minimize the impact on rates Edison proposes to phase nuclear fuel financing into rate base over a 10-year period. Because Edison believes that its credit ratings will not be affected if it is perceived as moving toward an appropriate capital structure and ratemaking treatment, it is willing to forego full equity support for the lease to mitigate rate increases. Edison estimates that its proposal for the SONGS nuclear fuel will increase rates by only $2.1 million in 1988 and $12.3 million over the three-year rate cycle.

Although Edison points out that the operating and life cycle characteristics of nuclear fuel are not the same as coal, gas, and oil, we believe that this is not enough to warrant a different ratemaking treatment. In fact, Edison proposes to finance nuclear fuel with a combination of short- and intermediate-term debt. While this might indicate that there is a need to factor in the cost of intermediate-term debt in deriving the carrying cost associated with nuclear fuel, it does not justify rate base treatment.

Edison also believes that the accounting change in and investor perceptions toward off-balance sheet financing require a change in its financing of nuclear fuel. We feel that these factors may affect risk, bond ratings, and the benefits of leases, but, again, they do not necessitate a change in ratemaking treatment.

As stated in prior decisions, we consider short-term debt instruments to be preferable in determining carrying charges on fuel. Fuel is a commodity that can be used as collateral for financing and is distinguishable from fixed plant and land. These factors lead us to the conclusion that fuel should not be afforded rate base treatment, regardless of its characteristics. As a result, we will not adopt Edison's proposed rate base treatment for SONGS unspent nuclear fuel and will direct Edison to calculate carrying costs on Palo Verde unspent nuclear fuel using the cost of short-term debt.

We will authorize Edison to record carrying costs on unspent nuclear fuel based on short-term debt and address these costs in ECAC proceedings. Since the carrying costs for SONGS unspent nuclear fuel is currently included in Edison's ECAC balancing account, no ratemaking change is necessary for this fuel. However, carrying costs for Palo Verde unspent nuclear fuel are included in Edison's intermediate major additions adjustment clause (IMAAC). Consistent with our discussion above, Edison should as of January 1, 1988 stop accruing carrying costs on Palo Verde unspent nuclear fuel in the IMAAC account and start accruing 100% of these costs in the ECAC balancing account based on the ECAC interest rate.

2. Coal Fuel Inventory

Edison has included in rate base $11.5 million for the minimum coal inventories necessary to support its coal-fired generation resources at Mohave and Four Corners. These minimum coal inventories are required in the event of a mine strike or other event which could interrupt the supply of coal. Both Four Corners and Mohave generating stations are remotely located, lack rail connection and waterways, and cannot be economically supplied from other mines should a supply interruption occur.

Consistent with its recommendation for nuclear fuel, PSD proposes that Edison's coal inventory be removed from rate base and carrying costs on coal inventory be based on short-term debt, recoverable through ECAC.

Again we acknowledge that some fuels such as coal have unique characteristics, but this does not justify rate base treatment. Our discussion in the nuclear fuel section above concerning carrying costs is equally applicable for coal inventory. We will not authorize Edison to receive rate base treatment on coal inventory. Starting January 1, 1988, Edison shall be allowed to accrue in its ECAC balancing account carrying costs on its coal inventory based on the ECAC interest rate. Edison's coal inventory level is not in dispute, we find its requested level reasonable for calculating carrying costs until Edison's next reasonableness review.

C. Palo Verde Reasonableness Review

Edison requests recovery of the costs associated with the California, Arizona, New Mexico and Texas (Four State Committee) investigation into the management and construction of Palo Verde. The costs for which Edison is requesting recovery were incurred for the purpose of paying for the investigation conducted by the Four State Committee and preparing an "affirmative case". The affirmative case was intended ultimately to demonstrate the reasonableness of Edison's investment at Palo Verde in the Palo Verde MAAC proceeding. The estimated cost associated with the investigation conducted by the Four State Committee and the preparation of Edison's affirmative case is $3.9 million. Edison is requesting that this amount be recovered in equal amounts over three years beginning in 1988.

FEA recommends that the Commission not allow the Company to recover $2.4 of the amount requested by Edison. According to FEA, these costs are related to the preparation of Edison's affirmative case and were not intended by the Commission to be recovered.

Edison argues that its affirmative case costs are similar to expenses associated with utility participation in (and preparation for) regulatory proceedings before the Commission and other agencies. The latter costs, Edison states, are normal costs of doing business and currently recovered in rates.

Although Edison's affirmative case costs for Palo Verde are similar to regulatory Commission expenses normally recovered through rates, Edison's request for recovery is not similar. First, Edison has not provided adequate justification that these costs were reasonably incurred. Second, regulatory Commission expenses are recovered prospectively, but Edison is requesting retroactive recovery.

Other than stating that its affirmative case was intended to demonstrate the reasonableness of its Palo Verde investment, Edison has not provided an explanation of what the costs were for and to whom they were paid. Assuming adequate justification, recovery of these costs requires Edison to seek our approval prior to their incurrence. Either by separate application or in an earlier proceeding, Edison should have requested approval for the expected cost of an affirmative case or requested the establishment of a mechanism for tracking these costs for later recovery. For these reasons Edison will not be authorized recovery of $2.4 million in affirmative case costs for Palo Verde.

D. Resource Plan

PSD is the only party that addressed the reasonableness of Edison's resource plan. During its participation PSD made specific recommendations concerning three Edison resource items: 1) the future status for many older and less efficient oil and gas generating units, 2) reduced minimum operating levels for various oil and gas generating plants, and 3) expansion of the Pacific Northwest (PNW) direct current (DC) intertie (discussed in a separate section).

1. Over View of Resource Planning

In sharp contrast to the situation Edison and other California utilities found themselves in less than a decade ago, Edison now has excess capacity that will last until well into the 1990's. This brings the "stay the course" policy of recent general rate cases into question. Under "stay the course" budget levels for resource related programs, such as research and development, conservation, and load management, were maintained at existing levels.

The approach which Edison now seems to embrace is to reduce high cost supplies and reduce expenditures on conservation and load management programs while maintaining the infrastructure necessary to gear up these programs. This policy would keep Edison's options open consistent with a least-cost strategy.

In support of its flexible policy for resource planning Edison provided a fairly detailed examination of its resource plans and associated forecasts spanning nearly twenty years and concluded that:

> "It is futile to pretend that our predictions of the future will be any more accurate than those of the past. The only certainty about the future is change; and
>
> What does this tell us about our future plans? We should separate the forecasting function from planning in the sense that even if the forecast turns out to be wrong, our planning is right."

In support of its new planning approach, Edison has presented a series of 12 scenarios, endeavoring to show the flexibility in its current (fall 1986) resource plan. Using this resource plan as the base case, there are a total of four resource options identified if lower demand forecasts were to result -- lower by as much as 5000 megawatts (MW). These are:

1. Change the number of units placed on cold standby (a storage option for older, less efficient oil and gas units).

2. Eliminate the Big Creek expansion project (an augmentation of Edison's Big Creek hydroelectric system).

3. Reduce the number of QFs; independent energy producers who's output Edison is required by law to purchase.

4. Cut back on energy management programs (conservation and load management).

In the event higher growth or an array of problems lead to the need for additional resources -- as much as 5000 MW more -- Edison has identified six resource options. They are:

1. Reduce the number of units placed in cold standby.

2. Increase purchases.

3. Develop Edison renewable and alternative resources (only in the scenario involving competitive ratemaking).

4. Install combustion turbines.

5. Increase energy management.

6. Build coal plants.

PSD generally agrees with Edison's policy, but does not consider its resource plan to be very flexible or dramatically different from past plans. To support its position PSD points out that Edison:

1. Has no effective control over the number of QFs.

2. Is currently planning on filing for a certificate of public convenience and necessity (CPCN) in the fall of 1987 for the Big Creek expansion project.

3. Needs 8 to 9 years to build a coal plant; slightly less for Ivanpah which has received partial California Energy Commission (CEC) approval.

4. May not be able to rely on purchases from other utilities for the same reasons that Edison would require additional resources.

Additionally, PSD states that with the exception of the Ivanpah project the biggest single source for Edison to either increase or decrease its resources is by adjusting the number of units in cold standby. PSD is concerned that the economic ramifications associated with the units recommended for cold standby can not be ascertained. These units are older, less efficient units, which in PSD's view could have high operation and maintenance costs and are sensitive to changes in oil and gas prices.

PSD's views, as detailed above, form the basis for its specific recommendations concerning Edison's plant refurbishments and retirements, minimum generation improvements and expansion of the DC intertie. These are discussed below.

2. Plant Refurbishments and Retirements

Over the last several years Edison has analyzed the need to refurbish or retire its oil and gas generating units which have approached or exceeded their original design or economic lives. In this proceeding Edison has no plans to retire or refurbish (preserved retirement) any of these units. Edison does plan to place various units totaling 894 MW into standby reserve by 1989. These units are identified in the following table.

Units Planned for Standby Reserve

Unit		Capacity (MW)	Placement Date
Etiwanda	1	132.0	1987
	2	132.0	1987
Highgrove	1	32.5	1988
	2	32.5	1988
	3	44.5	1988
	4	44.5	1988
Alamitos	1	175.0	1988
	2	175.0	1988
San Bernardino	1	63.0	1988
	2	63.0	1988
Total		894.0	

The cost of placing these units into standby reserve totals $343,000 of which Edison has requested $245,000 for test year 1988. Rather than refurbish any units, Edison is currently proceeding with the concept of sequenced maintenance, repair or replacement of deteriorated parts during routine maintenance outages.

CEC in preparation of its Electricity Report 6 (ER 6) reviewed Edison's plans for these aging units. As a result of the CEC analysis it made certain recommendations in its ER 6. PSD argues that Edison's plans are inconsistent with the CEC recommendations. As summarized by PSD, these recommendations state that Edison should:

1. Retire 1,760 MW by 1997.
2. Place 191 MW into standby reserve for three to five years beginning in 1990.
3. Not proceed with a refurbishment program for most of its oil and gas units.

Of primary concern to PSD is the absence of information on which to evaluate Edison's proposals and the inconsistency in the information that does exist.

PSD's specific concerns are listed below:

1. Edison's proposals are inconsistent with the CEC recommendations in ER 6. Whether the CEC conclusions are appropriate or not, the inconsistency needs to be addressed.

2. There has been no comprehensive update to the fall 1983 study performed by Edison, even though there have been dramatic changes in Edison's resource situation, fuel prices, etc.

3. Edison has repeatedly rejected PSD's requests to provide updated studies or information supporting its proposals for the oil and gas units.

PSD believes that without a comprehensive study evaluating the range of alternatives for the oil and gas units and a value-based reliability criteria, it is inappropriate to make commitments as to the future of these units. As a result, PSD recommends that: (1) a study which conforms with the guidelines shown in Exhibit 53 be provided in conjunction with Edison's fall 1988 resource plan, and (2) a value-based reliability criteria be submitted within three months from effective date of this decision.

Edison agrees with PSD's recommendations, however, it requests that: (1) the value-based reliability criteria be submitted coincident with its fall 1988 resource plan and (2) it be allowed to deviate from PSD's guidelines in Exhibit 53 in order to develop an appropriate study that meets PSD's needs.

We find PSD's recommendations as modified by Edison's requests reasonable.

3. <u>Minimum Generation Improvements</u>

Edison points out that as additional non-dispatchable QF capacity is added to its system there is a need for increased flexibility in dispatching its other resources. In recognition of this problem Edison's resource plan addresses six possible solutions:

1. Shift on-peak demand to off-peak.
2. Reduce the minimum generation output.
3. Purchase peaking power.
4. Storage of off-peak energy for use on-peak.
5. QF dispatchability
6. Shift off-peak production to on-peak.

Of the six items Edison has only requested funding in this proceeding for items 1 and 2. Item 1, programs which shift on-peak demand to off-peak, are addressed in the demand side management section of this decision. Item 2 is the only item with which PSD's resource witness takes issue.

Edison has requested $4.2 million in test year 1988 to reduce its minimum operating load for certain oil and gas generating units. In addition, it capitalized $15.1 million in 1986 and expects to incur a like amount in 1989; both for reducing the minimum operating load. The following table details the units which Edison has and proposes to modify and the cost of modification.

Units Planned for a Reduction in the Minimum Generation Output
(Dollars in Thousands)

Unit		Completion Date (MW)	Capacity Reduction	Cost
Ormond Beach	2	1986	200	$15,050.0
	1	1989	200	15,050.0
Alamitos	5	1988	50	652.3
	6	1988	50	652.3
Redondo Beach	7	1988	50	652.3
	8	1988	50	652.3
Hunington Beach	2	1988		395.0
	1	1988		595.0
Mandalay	2	1988		595.0
	1	1989		595.0

Edison proposes to reduce the minimum generation capability at the Ormand Beach, Alamitos, and Redondo Beach units by making plant modifications. At the Huntington Beach and Mandalay units Edison proposes to go from three daily operating shifts to two, two-shifting, with the unit shut down during the third shift.

After performing cost-effective analyzes on Edison's proposed projects, PSD concluded that only the Ormand Beach unit 2 project is cost-effective. PSD recommends that the costs for an experimental two-shifting project at Ormond Beach unit 2 and Huntington Beach unit 2 be allowed. For all other projects, PSD recommends no rate recovery in this proceeding, but that Edison consider a separate application or review in an attrition proceeding to present these projects when it has the requisite information to support them.

Edison's major concern with PSD's recommendations is not the need for further justification, but recovering its costs in a timely fashion. Since Edison bears the burden of proving the cost-effectiveness of these expenditures, its cost recovery is mainly within its control. We will adopt PSD's recommendation because it provides ample opportunity for Edison to receive timely ratemaking treatment on the expenditures it can justify to be cost-effective.

E. Sylmar-Pacific High Voltage Direct Current Intertie Expansion Project (DC Expansion)

In its application Edison has included $104.6 million in estimated plant additions for the DC Expansion. This project is a major augmentation of the existing high voltage DC line which connects southern California with the PNW. Once completed, the DC Expansion would increase the transfer capability for power between California and the PNW by 1030 MW.

The DC Expansion is a joint venture of Edison and LADWP. Edison's 50% share is on behalf of itself, PG&E, and SDG&E. To date Edison has spent approximately $4 million. A portion of the $4 million has been paid for engineering and construction services as part of a $70 million fixed price contract with Brown-Boveri. If Edison were to withdraw form the project it would remain responsible for one-half of its 50% interest in that agreement, or approximately $17.5 million. The project is currently under construction and is expected to be completed by December 1988.

This was the most actively debated issue in the resource planning area. The source of the controversey was the assumptions used to evaluate the project's cost-effectiveness. As a result PSD developed its own cost-effectiveness analysis and concluded that Edison should not participate in the project.

Edison takes the position that the DC Expansion is a cost-effective project and the lowest cost alternative to securing additional transmission capacity to the PNW. To evaluate the cost-effectiveness Edison used a decision analysis model or "decision tree" in which one or more alternative values for each of the input assumptions are placed in the computer model, weighted by the respective probabilities of their occurrence. The output of the model is a range of possible benefits with a probability assigned to each. Only capital related items are included in the cost calculations. Expenses are treated as a reduction to benefits.

The decision analysis evaluation Edison performed shows the present value of expected benefits of 729 different sensitivities to be $206 million. As a result of this analysis Edison believes that the estimated cost of $104.6 million is unquestionably prudent and that the project should be pursued to the benefit of its ratepayers.

While PSD does not take issue with the use of a decision tree, it identified some problems with the way Edison set up its model:

1. The model was biased by using a nominal carrying charge rate to levelize the capital costs associated with the project's avoided capacity. In its cost of service study, used to develop marginal costs for revenue allocation, rate design, QF payments and evaluation of conservation and load management programs, Edison used a real carrying charge rate.

2. The model does not properly account for the reduced benefit of taking capacity during the summer only, instead of all year.

3. Edison's current excess capacity situation was not taken into consideration. In valuing capacity from QFs, Edison applied an energy reliability index (ERI) to reflect the relative value based on its need for capacity.

PSD's analysis used a LOTUS spreadsheet to compute annual costs and benefits over the project's 30 year life (1989-2018.) A real carrying charge rate was applied to Edison's share of the project costs to get a stream of levelized payments analogous to the real cost of renting the line. Annual operation and maintenance costs were added to get a stream of total costs.

PSD ran a base case and 11 scenarios which tested sensitivities to changes in the critical variables, including ERIs, capacity prices, capacity availability in summer only and all year, duration of purchases, quantities of economy energy and Edison's avoided energy cost.

The net present values for the base case are negative $171.1 million (capacity all year) and negative $100.8 million (capacity summer only). The corresponding benefit to cost ratios are 0.09 and 0.46 respectively. All of the scenarios have net present values that are negative and benefit to cost ratios that are less than one.

While it does not recommend the use of PSD's cost-effectiveness analysis, Edison disagrees with some of the assumptions used and has calculated their impact on PSD's present value estimate. The following table summarizes these assumption differences:

Effect of Edison's Assumptions on PSD's Cost-Effective Analysis

Assumptions	Change in Rate Base* (Dollars in Millions)
1. Value of Summer Only Capacity - Edison 97%; PSD 72%	$ 9
2. Full Value of PNW Capacity - Edison 1993; PSD 1997	5
3. PNW Capacity Availability - Edison Throughout Project Life; PSD Ending In 1996	36
4. Gas Prices - Edison Average Prices; PSD Marginal Prices	14
5. Value of Purchased Energy	10
6. BPA Economy Energy Price	13
7. Forecasted Gas Prices	40
Total	$127

* Assumes benefit to cost ratio of 1.0.

1. Assumption Differences

a. Value of Summer Only Capacity

Edison claims that PSD chose the wrong marginal demand cost allocation for summer only capacity by using the allocation factor for transmission and primary distribution in stead of generation. PSD's allocation factor assumes that capacity is coming from a single generating unit rather than the entire PNW system. In addition, Edison believes that PSD incorrectly used the on-peak factor to apply to the value of the combustion turbine. Edison recommends using the sum of the on-peak and mid-peak allocation factors since these reflect the amount of combustion turbine capacity that would be deferred.

As a result of these differences Edison's allocation factor for summer only capacity is 0.97 as compared to PSD's factor of 0.72. PSD's present value calculation would increase by $9 million if Edison's 0.97 allocation factor were used.

b. Value of PNW Capacity

In determining the value of excess capacity PSD included the Big Creek Expansion Project, the California-Oregon Transmission Project, and unfunded energy management projects. These amount to approximately 1,400 MW of peaking resource additions. Edison argues that these resources are either not funded or not under construction and should be removed in determining the capacity value factor.

If these peaking resources are removed capacity would receive full value in 1993 rather than 1997 as estimated by PSD. This would increase PSD's present value calculation by $5 million.

c. PNW Capacity Availability

PSD assumed that PNW firm capacity would be available to California only through 1997. This was based on PSD's view that:

1. Bonneville Power Authority's (BPA) most recent resource plan would require PNW utilities to commit running combustion turbines, old, small, inefficient oil, gas and diesel generators, and interrupting load as needed to direct service industries, primarily aluminum industries.

2. The proposed Long-Term Intertie Access Policy of BPA limits capacity exports on the intertie (including the DC Expansion) to 2550 MW, even when the intertie will be 6300 MW (5500 MW firm).

3. The conservation programs included in BPA's resource plan would have less than the 66% capacity factor assumed by BPA.

4. BPA's resource plan shows that the PNW will have limited capacity for firm sales to California by the planning year 2003-2004.

Edison disagrees with PSD's conclusion and believes that there will be sufficient surplus summer capacity available to fill the alternating current (AC) intertie, AC intertie uprate, DC intertie, and DC Expansion well into the 21st century. In arriving at this conclusion Edison relied on the resource plans of BPA and the Northwest Power Planning Council and the March 1987 Northwest Regional Forecast of the Pacific Northwest Utilities Conference Committee. Edison's interpretation of these forecasts indicates a need beyond 1997 for additional capacity to serve the PNW winter load, thus resulting in additional surplus summer capacity.

The difference between PSD's and Edison's estimate of available surplus summer capacity is $36 million based on PSD's analysis.

d. Gas Prices

PSD used Edison's marginal gas price in its analysis to evaluate the DC Expansion's cost-effectiveness against other resource options. The marginal gas price PSD used represents the Tier II rate that Edison pays SoCal.

Currently Edison pays SoCal on a fixed monthly demand charge and a declining block Tier I/Tier II commodity rate. Based on the adopted sales forecast in SoCal's recent consolidated adjustment mechanism decision, D.87-01-046, the current Tier I quantity is about 18% of Edison's total purchases from SoCal. The volumes Edison is billed at the higher Tier I rates is adjusted periodically based on Edison's purchases.

Edison recommends using its average gas price because it better reflects this linkage between Tier I and Tier II and is used as the basis for QF energy payments.

If average gas prices are substituted for marginal prices PSD's present value analysis would increase by $14 million.

e. Value of Purchased Energy

PSD did not time differentiate the value of energy purchased over the DC intertie. Edison believes this fails to recognize that the majority of the energy is expected to be purchased during the on-peak and mid-peak time periods. To properly reflect the value of the energy at the time received Edison suggests that the incremental energy rates (IERs) used in determining utility payments for QF energy be applied. Edison estimates that using PSD's IERs would increase the present value of PSD's cost-effectiveness analysis by $10 million.

f. BPA Economy Energy Price

PSD's analysis assumed economy energy costs were 21.8 mills/kwh in 1989. However, Edison points out this is in sharp conflict with PSD's Exhibits 60 and 60-A, marginal cost, where it recommends a price of 18 mills/kwh in 1988. Edison considers PSD's latter estimate of 18 mills/kwh more appropriate because it better reflects the historical relationship of economy energy prices being 60% of Edison's avoided energy price (natural gas).

PSD believes that the price of economy energy should be based on the BPA proposed rate cap formula to be consistent with current price behavior under BPA's Intertie Access Policy. It is PSD's view that the overall objective of BPA is to maximize its revenues on sales to California. To support this view PSD cites testimony in Edison's ECAC A.87-02-019 which refers to BPA's increased rates and spilled water to avoid producing electricity for sale to California.

The difference between PSD's 18 and 21.8 mills/kWh price for BPA's economy energy sales impacts PSD's analysis by $13 million.

g. Forecasted Gas Prices

PSD forecasted gas prices using the projected cost of low sulfur waxy residue (LSWR), No. 6 fuel oil. A 1986 price of $12.50/barrel for Singapore fuel oil was used as PSD's base price. Following adjustments for sales tax, shipping cost, and import tax, PSD applied a growth rate of 5 percent until 1991. After 1997 PSD used the CEC's 1986 real growth rate forecast and gross national product (GNP) implicit price deflation.

Edison's major concern with PSD's forecast is its low starting point. This yields a forecast for 1990 of $15.38/barrel which is considerably below the postings for Singapore LSWR of between $16.60 and $17.70 for the first part of this year.

Edison, in its analysis using the PSD computer spreadsheet, evaluated the present value benefits of using both the CEC ER-6, moderate price forecast as well as the Edison projection used in its August 1986 decision analysis evaluation of the DC Expansion. Use of these forecasts resulted in the present value benefits of the DC Expansion being increased by $32 million for the CEC forecast and by $40 million for the Edison forecast.

2. <u>Discussion</u>

The testimony in this proceeding clearly shows that Edison intended to participate in the DC Expansion project with or without our approval. By letter dated August 27, 1986 Edison stated that:

> "...we do not believe a Certificate of Public Convenience and Necessity is required for this upgrade....We have also accepted the responsibility and attendant risk, of demonstrating the reasonableness of our investment in the appropriate rate case at the time the expanded HVDC facilities become operational."

Edison's actions involving the DC Expansion cause us deep concern. First, Edison's preliminary estimate of the project's costs as provided to PSD was $55 million. This estimate was considered to be incomplete and revised to $104 million a year later. Second, Edison steadfastly refused to file a CPCN stating that the project was only an upgrade and that there was not adequate time to process a CPCN and construct the facilities to meet a BPA completion date. Third, Edison informed the PSD that the reasonableness of project expenditures would be demonstrated after the project became operational. However, Edison neglected to tell PSD that it would request ratemaking treatment prior to the operational date. Finally, before Edison's general rate case application it justified the cost-effectiveness of the DC Expansion to PSD based on the the availability of BPA economy energy. In this proceeding Edison has premised the need for the project primarily on the availability of firm capacity.

PU section 1102 Code (Ch. 1430, Stats. of 1986) states that:

> "...an electrical corporation proposing to construct an electrical transmission line to the northwestern United States shall provide the Commission with sufficient reliable information that the proposed line...will be cost-effective."

PSD is responsible for analyzing all projects affected by PU Section 1102 and providing independent recommendations for our consideration. While PSD diligently attempted to fulfill its responsibilities, we believe Edison's efforts in providing PSD the most complete and reliable information available were less than exemplary.

Although this decision does not address the issue of when CPCNs are required, we caution Edison and other electric utilities that in the future we will expect a complete showing justifying the cost-effectiveness of similar projects prior to their receiving ratemaking consideration. In addition, utilities will be expected to cooperate with PSD to ensure that a utility's showing meets the minimum requirements of a CPCN application. This procedure should be similar to that used for NOI filings, i.e., deficiencies identified by PSD and corrected by the utility before acceptance.

The critical issue involving the DC Expansion project is the appropriate ratemaking treatment to be afforded Edison's expenditures. Edison has included $104.6 million in plant-in-service for this project and its cost-effectiveness analysis yields a present value of $206 million. PSD based on its cost-effectiveness analysis recommends that Edison be limited to recognition of an investment no greater than $47.8 million irrespective of the actual expenditures.

As previously discussed Edison believes that a CPCN is not required for this project, but is requesting ratemaking treatment prior to completion. For us to address Edison's request we must determine what is an appropriate amount to be included in rates. This requires a determination of the cost-effectiveness of this project as performed in CPCN proceedings. Additionally, PSD recommends that a cap be placed on the amount to be included in rates as required in CPCN applications. We concur with PSD's recommendation.

Since Edison has quantified its differences with PSD's cost-effectiveness assumptions, we will use PSD's analysis to determine an appropriate ratemaking value to be placed on the DC Expansion. The following discussion will address each PSD assumption which Edison contests.

a. & e. Value of Summer Only <u>Capacity and Purchased Energy</u>

Edison disagrees with PSD's lack of time differentiating the value of energy purchased and capacity received over the DC intertie. We believe it is appropriate to reflect the value of energy and capacity by time of day. This is done in rate design with time-of-use rates and with QF energy payments. Time differentiating energy and capacity will increase PSD's analysis by $19 million.

b. & c. Value and Availability <u>of PNW Capacity</u>

PSD, in valuing PNW capacity, has included 1400 MW of peaking resource additions which are not funded or not under construction, but excluded similar uncertain capacity in determining the availability of PNW capacity. We agree with PSD that a conservative approach should be taken with respect to capacity availability, but find its approach is inconsistent in its a present value of $206 million. PSD based on its cost-effectiveness analysis recommends that Edison be limited to recognition of an investment no greater than $47.8 million irrespective of the actual expenditures.

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b. & c. Value and Availability of PNW Capacity

PSD, in valuing PNW capacity, has included 1400 MW of peaking resource additions which are not funded or not under construction, but excluded similar uncertain capacity in determining the availability of PNW capacity. We agree with PSD treatment of capacity resources. We believe that the cost-effectiveness analysis will be consistent in its assessment of expected capacity by excluding 1400 MW in valuing capacity. This will increase PSD's analysis by $5 million.

d. Gas Prices

In evaluating the DC Expansion PSD used Edison's marginal gas price as opposed to its average gas price. Although Edison's marginal gas price does not represent its true avoided cost under SoCal's current rate structure, our evaluation of this project is on a long run basis. Over the long-term we expect the rate structures under consideration for the gas industry will result in Edison's incremental gas purchases priced at the margin. We will use PSD's marginal gas prices for analyzing the cost-effectiveness of the DC Expansion project.

f. BPA Economy Energy Price

We agree with PSD that the price of BPA's economy energy should be 85% of Edison's avoided energy price to be consistent with BPA's current price behavior under its Intertie Access Policy. No change in PSD's cost-effectiveness analysis is warranted.

g. Forecasted Gas Prices

PSD's forecasted gas prices are based on the 1986 price of LSWR. While 1987 has seen a considerable increase in LSWR prices, it is not unusual to see large fluctuations in these prices over a short time period. Because of this and the wide divergence in projected gas prices we will average PSD's and Edison's forecasts. This results in a $20 million increase in PSD's present value of the DC Expansion.

As a result of our adjustments to PSD's assumptions we find the present value of the DC Expansion to be $91.8 million. We will authorize Edison to rate base the actual cost for Edison's share of the project or $91.8 million, whichever is lower. Whatever the amount, ratemaking treatment will not become effective until the DC Expansion is operational and will be subject to refund that a conservative approach should be taken with respect to capacity availability, but find its approach is inconsistent in its treatment of capacity resources. We believe that the cost-effectiveness analysis will be consistent in its assessment of expected capacity by excluding 1400 MW in valuing capacity. This will increase PSD's analysis by $5 million.

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pending a reasonableness review. These items are addressed in more detail in the section that discusses PU Section 463.

F. Treatment of Certain Plant Items Pursuant to PU Section 463

On March 2, 1987, PSD filed a motion requesting that Edison be ordered to amend its Application to exclude all costs associated with uncompleted capital projects in excess of $50 million. Specifically, PSD moved that Edison be required to file separate applications in order to seek rate relief for four projects: Balsam Meadow Hydroelectric Generating Plant, Devers-Valley-Serrano 500 KV Transmission Line, DC Expansion, and SONGS 1 capital additions in connection with the integrated living schedule (ILS). PSD's motion was based on the argument that PU Section 463 precludes consideration of uncompleted capital projects in excess of $50 million in future test year rate proceedings. Edison filed a response to PSD's motion, on March 16, 1987, arguing that the requirements of PU Section 463 are compatible with future test year ratemaking and that post-operational reasonableness reviews can be made in a subsequent general rate case proceeding.

On May 5, 1987, ALJ Ferraro issued a ruling denying PSD's motion, finding that PU Section 463 does not require a reasonableness review prior to establishing rates for capital projects or restrict the Commission from setting rates for capital projects on a prospective basis. In that ruling Edison and PSD were directed to develop, for inclusion in the rate case plan for this and future Edison general rate cases, a detailed procedure which would allow for the continuance of the Commission's traditional ratemaking process with respect to the projects addressed in PSD's motion. Attached as Appendix A is the proposed procedure jointly submitted by Edison and PSD.

The proposed procedure provides for modification of the existing MAAC to include recorded investment-related revenue requirement and the recorded revenues related to specific plant

Whatever the amount, ratemaking treatment will not become effective until the DC Expansion is operational and will be subject to refund pending a reasonableness review. These items are addressed in more detail in the section that discusses PU Section 463.

On November 23, 1987 PSD filed a motion to set aside submission with respect to the high voltage DC terminal expansion project and to compel production of documents. PSD states that Edison has failed to disclose the existence of various agreements, including a December 2, 1985 letter agreement with LADWP, that significantly alter the anticipated usage of several transmission projects including the DC Expansion project. Since Edison's anticipated usage of these projects is pivotal in establishing its need for and the cost-effectiveness of the projects, the withheld information has a significant bearing on whether the projects should be pursued.

In the case of the DC Expansion project the PSD requests that it be withdrawn from the submitted test year 1988 general rate case and be consolidated with any subsequent consideration of the Devers-Palo Verde transmission line No. 2. PSD's request for consolidation is based on Edison/LADWP agreements which link the two projects and the need to consider transmission projects together so that their interrelationships can be assessed.

In response to PSD's motion Edison argues that the letter agreement dated December 2, 1985 was merely a letter in which the parties expressed their intent to work toward a definitive agreement at a later time. Additionally, Edison states that: (1) it is not necessary to set aside the submission of the DC Expansion project to protect the interest of ratepayers, (2) there is no final agreement to consider, (3) Edison and LADWP agreed that the proposed agreement will not be disclosed to third parties, and (4) without Commission authorization PSD cannot compel production of the proposed agreement.

additions estimated to cost more than $50 million. Investment-related revenue requirement is defined as the sum of (1) depreciation; (2) ad valorem taxes; (3) taxes based on income, including any appropriate tax adjustments; and (4) return on CPUC jurisdictional rate base as set forth in the applicable tariff.

Edison and PSD propose that the procedure apply when plant is to be reflected in rates for the first time, and is eligible for inclusion in MAAC. Specifically, PSD and Edison propose that:

1. Plant additions to be included in MAAC be determined through the general rate case proceeding.

2. In-service criteria for each project to be included in MAAC be determined in the general rate case proceeding.

3. The initial investment-related revenue requirement and resultant MAAC rates for each project be determined in the general rate case proceeding, the initial MAAC rate level be equal to 75% of the revenue requirement, and the revenue requirement reflect the utility's estimated investment-related costs or the Commission's adopted cost cap level, whichever is less.

4. Noninvestment-related expenses associated with each project be determined in the general rate case and reflected in base rates through the general rate case.

5. A separate advice letter filing be made to place each project into the MAAC on its in-service date.

6. Previously determined MAAC rate changes for a project be implemented at the next regularly scheduled ECAC or base rate level change after its in-service date to minimize the number of rate changes occurring during the year.

7. Between the in-service date of a project and the implementation of MAAC rates

Although we share PSD's concerns that information may exist which could have a bearing on the cost-effectiveness of the DC Expansion project, we do not find it necessary to remove this project from Edison's general rate case. However, Edison is put on notice that we intend to give further consideration to the cost-effectiveness evaluation adopted in this decision in conjunction with our analysis of Edison's other transmission projects and/or agreements with LADWP. The cost-effectiveness cap placed on the DC upgrade by this decision is for the upgrade presented to us by the utility. If the agreements called to our attention by the staff motion affect the nature and use of the upgrade, the cost-effectiveness cap will have to be redetermined in the new context. Should our subsequent cost-effectiveness review yield lower results, we will adjust the DC Expansion cap adopted in this decision. Finally, we consider our further review of the DC Expansion cap appropriate because Edison has freely assumed the risk of building this project without a CPCN and two years ago signed a letter agreement with LADWP which could impact the cost-effectiveness of the DC Expansion and other transmission projects without informing this Commission or our staff.

PSD's motion to set aside submission of the DC Expansion project is denied. However, we will grant PSD's motion to compel Edison to produce the documents requested in attachment 6 to the motion. Edison will be required to respond to PSD's data requests contained in attachment 6 within 10 days from the effective date of this decision.

F. <u>Treatment of Certain Plant Items Pursuant to PU Section 463</u>

On March 2, 1987, PSD filed a motion requesting that Edison be ordered to amend its Application to exclude all costs associated with uncompleted capital projects in excess of $50 million. Specifically, PSD moved that Edison be required to file separate applications in order to seek rate relief for four reflecting that project, all recorded investment-related revenue requirement associated with that project be recorded as an undercollection in the MAAC balancing account pursuant to MAAC procedures. After implementation of MAAC rates both the recorded revenue and recorded investment-related revenue requirement be reflected in the MAAC balancing account.

8. The ultimately adopted reasonable level of investment for each project be reflected in rates pursuant to an application filed to establish the reasonable and prudent level of recorded costs of the completed project. Such applications should be filed no later than six months after the final portion of each project is placed in-service.

For this general rate case Edison and PSD propose that MAAC rate level increases, equal to 75% of the annualized revenue requirement, be authorized for each of four projects. These projects together with their estimated in-service date, project cost, and annualized revenue requirement are listed below:

Project	Projected Initial In-Service Date	Project* Cost	Annualized# Revenue Requirement
		(Dollars in Thousands)	
1. Balsam Meadow Hydroelectric Generating Project	Prior to 1/1/88	$284,655	$ 47,730
2. Devers-Valley-Serrano 500 kV T/L	July 22, 1987	127,819	25,965
3. DC Expansion	December 31, 1988	91,631	17,652
4. Devers-Palo Verde No. 2 Transmission Line	June 1, 1990	207,952	39,189

* First year's rate base on date eligible for inclusion in MAAC.
\# 100% of CPUC jurisdictional revenue requirement.

projects: Balsam Meadow hydroelectric generating plant, Devers-Valley-Serrano 500 KV transmission line, DC Expansion, and SONGS 1 capital additions in connection with the integrated living schedule (ILS). PSD's motion was based on the argument that PU Section 463 precludes consideration of uncompleted capital projects in excess of $50 million in future test year rate proceedings. Edison filed a response to PSD's motion, on March 16, 1987, arguing that the requirements of PU Section 463 are compatible with future test year ratemaking and that post-operational reasonableness reviews can be made in a subsequent general rate case proceeding.

On May 5, 1987, ALJ Ferraro issued a ruling denying PSD's motion, finding that PU Section 463 does not require a reasonableness review prior to establishing rates for capital projects or restrict the Commission from setting rates for capital projects on a prospective basis. In that ruling Edison and PSD were directed to develop, for inclusion in the rate case plan for this and future Edison general rate cases, a detailed procedure which would allow for the continuance of the Commission's traditional ratemaking process with respect to the projects addressed in PSD's motion. Attached as Appendix A is the proposed procedure jointly submitted by Edison and PSD.

The proposed procedure provides for modification of the existing MAAC to include recorded investment-related revenue requirement and the recorded revenues related to specific plant additions estimated to cost more than $50 million. Investment-related revenue requirement is defined as the sum of (1) depreciation; (2) ad valorem taxes; (3) taxes based on income, including any appropriate tax adjustments; and (4) return on CPUC jurisdictional rate base as set forth in the applicable tariff.

Edison and PSD propose that the procedure apply when plant is to be reflected in rates for the first time, and is eligible for inclusion in MAAC. Specifically, PSD and Edison propose that:

The difference in the revenue requirements shown above and those contained in Appendix A reflects the adopted cost of capital and other revenue requirement items contained in this decision.

Additionally, PSD and Edison agreed that the SONGS 1 ILS, which comprises many numerous distinct and individual projects, should not be subject to this procedure, but should instead be reflected in base rates through the normal general rate case procedure in the same manner as any other plant addition which costs less than $50 million.

We adopt the criteria set forth in the joint PSD/Edison exhibit, Appendix A, for implementing PU Section 463. Our only modifications are to reflect the revenue requirement factors adopted in this decision and the fact that the Devers-Valley-Serrano project is presently in-service.

In Exhibit 240 Edison requested that the ratemaking treatment discussed above be implemented for the Devers-Valley-Serrano project. Based on Exhibit 240 we conclude that this project was placed into service on July 22, 1987 and meets the criteria set forth in Exhibit 203 and adopted above. As previously discussed the initial MAAC rate for PU Section 463 projects will be set at 75% of the project's revenue requirement. For the Devers-Valley-Serrano project we will increase Edison's MAAC rate by $19.5 million or 0.03 cents/kWh which equates to 75% of the CPUC jurisdictional investment-related revenue requirement.

G. Research, Development and Demonstration

Edison has requested authorization of $40.1 million (1986 dollars) in test year 1988 funding for its RD&D plan. This represents approximately a 10% reduction from the authorized level of funding for 1986.

As proposed by Edison the RD&D plan consists of 12 programs grouped under six research areas. These areas are intended to correspond to the RD&D objectives and guidelines

1. Plant additions to be included in MAAC be determined through the general rate case proceeding.

2. In-service criteria for each project to be included in MAAC be determined in the general rate case proceeding.

3. The initial investment-related revenue requirement and resultant MAAC rates for each project be determined in the general rate case proceeding, the initial MAAC rate level be equal to 75% of the revenue requirement, and the revenue requirement reflect the utility's estimated investment-related costs or the Commission's adopted cost cap level, whichever is less.

4. Noninvestment-related expenses associated with each project be determined in the general rate case and reflected in base rates through the general rate case.

5. A separate advice letter filing be made to place each project into the MAAC on or after its in-service date.

6. Previously determined MAAC rate changes for a project be implemented at the next regularly scheduled ECAC or base rate level change after its in-service date to minimize the number of rate changes occurring during the year.

7. Between the in-service date of a project and the implementation of MAAC rates reflecting that project, all recorded investment-related revenue requirement associated with that project be recorded as an undercollection in the MAAC balancing account pursuant to MAAC procedures. After implementation of MAAC rates both the recorded revenue and recorded investment-related revenue requirement be reflected in the MAAC balancing account.

8. The ultimately adopted reasonable level of investment for each project be reflected in rates pursuant to an application filed to establish the reasonable and prudent level

established in D.82-12-005. Edison's research areas and programs are outlined in the table below. All amounts in this section are in 1986 dollars.

Edison's 1988 RD&D Plan

Research Area	Programs
1. System Operations and Efficiency Improvements	1. Load Control/Customer Interface 2. Storage and Energy Management Technologies 3. Facilities Conversion for Optimal Operation
2. Advanced Energy Technologies	4. Competing for the Customer 5. Advanced Energy Conversion 6. Long Range/High Pay-back Technologies
3. Health and Safety	7. Occupational and Community Safety
4. Renewable Energy Resources	8. Renewable Energy Conversion
5. Environmental Improvement	9. Air Quality Enhancement 10. Natural Resources Management
6. Energy Conservation and Efficient Resource Utilization	11. Customer Energy Management 12. Alternate Fuels

1. PSD's Position

After reviewing Edison's RD&D plan, PSD believes that the competing for the customer program and the electric transportation project are diametrically opposed to the guidelines. These are described as follows:

of recorded costs of the completed project. Such applications should be filed no later than six months after the final portion of each project is placed in-service.

For this general rate case Edison and PSD propose that MAAC rate level increases, equal to 75% of the annualized revenue requirement, be authorized for each of four projects. These projects together with their estimated in-service date, project cost, and annualized revenue requirement are listed below:

Project	Projected Initial In-Service Date	Project* Cost	Annualized# Revenue Requirement
		(Dollars in Thousands)	
1. Balsam Meadow Hydroelectric Generating Project	December 1, 1987	$284,655	$ 47,730
2. Devers-Valley-Serrano 500 kV T/L	July 22, 1987	127,819	25,965
3. DC Expansion	December 31, 1988	91,631	17,652
4. Devers-Palo Verde No. 2 Transmission Line	June 1, 1990	207,952	39,189

* First year's rate base on date eligible for inclusion in MAAC.
# 100% of CPUC jurisdictional revenue requirement.

The difference in the revenue requirements shown above and those contained in Appendix A reflects the adopted cost of capital and other revenue requirement items contained in this decision.

Additionally, PSD and Edison agreed that the SONGS 1 ILS, which comprises many numerous distinct and individual projects, should not be subject to this procedure, but should instead be reflected in base rates through the normal general rate case procedure in the same manner as other plant additions which cost less than $50 million.

a. Competing for the Customer

<u>Total Energy Facilities</u> - determine the feasibility of Edison becoming a total energy supplier both near existing generating stations and also to complexes requiring a central energy supply located away from existing generating stations.

<u>Advanced Space Conditioning</u> - work toward increasing the efficiency of space conditioning equipment and providing customers with cost-effective options for shifting electric space cooling loads from on-peak to off-peak periods.

<u>On-Site Generation and Cogeneration Project</u> - explore and develop various small generating technologies which can provide an alternative to traditional electric service.

b. Storage and Energy Management Technologies

<u>Electric Transportation</u> - accelerate development of commercial electrically powered transportation involving prototype vehicle evaluations, development and evaluation of advanced vehicle/battery concepts, formulation of commercialization strategy, and electrified roadway demonstrations.

PSD states that these are marketing programs designed to develop additional sales, build load, and to avoid losing sales to self-generation. PSD believes that marketing and load building programs are very short-sighted and, while they take advantage of current excess capacity, promote usage that ultimately needs to be curtailed. In addition, PSD is concerned that Edison's use of ratepayer monies for the development of these programs will primarily benefit its investors, either through the utility company or its unregulated subsidiaries. Finally, PSD argues that Edison's participation in the electric transportation project should be

We adopt the criteria set forth in the joint PSD/Edison Exhibit 203, Appendix A, for implementing PU Section 463. Our only modifications are to reflect the revenue requirement factors adopted in this decision and the fact that the Devers-Valley-Serrano and Balsam Meadow projects are presently in-service.

In Exhibits 240 and 241 Edison requested that the ratemaking treatment discussed above be implemented for the Devers-Valley-Serrano and Balsam Meadow projects. Based on these exhibits we conclude that the Devers-Valley-Serrano project was placed into service on July 22, 1987 and the Balsam Meadow project was placed in service on December 1, 1987. Additionally, both these projects meet the criteria set forth in Exhibit 203 and adopted above. As previously discussed the initial MAAC rate for PU Section 463 projects will be set at 75% of the project's revenue requirement. For the Devers-Valley-Serrano and the Balsam Meadow projects we will increase Edison's MAAC rate by $55.3 million or 0.085 cents/kWh which equates to 75% of the CPUC jurisdictional investment-related revenue requirement.

Finally, Edison in its comments raised the issue of the impact of the Financial Accounting Standards Board statement 92, Regulated Enterprises - Accounting for Phase-in Plans, impact on Exhibit 203. Since the only impact would be of an accounting nature, we will leave this issue open to be addressed in the future.

G. Research, Development and Demonstration

Edison has requested authorization of $40.1 million (1986 dollars) in test year 1988 funding for its RD&D plan. This represents approximately a 10% reduction from the authorized level of funding for 1986.

As proposed by Edison the RD&D plan consists of 12 programs grouped under six research areas. These areas are intended to correspond to the RD&D objectives and guidelines established in D.82-12-005. Edison's research areas and programs through the Electric Power Research Institute (EPRI), since it will be doing work of a parallel nature.

Another area in which PSD recommends a reduction in Edison's budget is the high performance peaking technologies project. PSD recommends that Edison's budget for this project be cut by $225,000 by combining the monitoring research activities.

PSD also disagrees with Edison's shift in priorities from developing new resources to consuming existing conventional resources at an expanding rate. Edison reduced its original budget for the alternate fuels, occupational and community safety, and advanced energy conversion programs by $2.4 million and other programs by $2.5 million. These reductions were made to provide funding for the competing for the customer and load control/customer interface programs and the electric transportation project without increasing the overall RD&D budget. PSD recommends reinstatement of $1.5 million program cuts for the alternate fuels, occupational and community safety, and advanced energy conversion programs.

The following table summarizes Edison's and PSD's recommended RD&D program expenditures.

are outlined in the table below. All amounts in this section are in 1986 dollars.

Edison's 1988 RD&D Plan

Research Area	Programs
1. System Operations and Efficiency Improvements	1. Load Control/Customer Interface
	2. Storage and Energy Management Technologies
	3. Facilities Conversion for Optimal Operation
2. Advanced Energy Technologies	4. Competing for the Customer
	5. Advanced Energy Conversion
	6. Long Range/High Pay-back Technologies
3. Health and Safety	7. Occupational and Community Safety
4. Renewable Energy Resources	8. Renewable Energy Conversion
5. Environmental Improvement	9. Air Quality Enhancement
	10. Natural Resources Management
6. Energy Conservation and Efficient Resource Utilization	11. Customer Energy Management
	12. Alternate Fuels

1. PSD's Position

After reviewing Edison's RD&D plan, PSD believes that the competing for the customer program and the electric transportation project are diametrically opposed to the guidelines. These are described as follows:

a. **Competing for the Customer**

Total Energy Facilities - determine the feasibility of Edison becoming a total energy supplier both near existing

Comparison of Edison and PSD RD&D Expenditures
(1986 Dollars)

Program Area	Edison	PSD	Edison Exceeds PSD
(Dollars in Thousands)			
1. Load Control/ Customer Interface	$5,075	$5,075	$ 0
2. Competing for the Customer	2,540	0	2,540
3. Storage & Energy Management Technologies	3,005	2,005	1,000
4. Customer Energy Management	3,700	3,700	0
5. Alternate Fuels	1,175	1,850	(675)
6. Air Quality Enhancement	2,000	2,000	0
7. Facilities Conversion for Optimal Operation	1,750	1,750	0
8. Renewable Energy Conversion	1,180	1,180	0
9. Occupational & Community Safety	1,000	1,550	(550)
10. Advanced Energy Conversion	500	525	(25)
11. Natural Resources Management	500	500	0
12. Long Range/High Pay-back Technologies	475	475	0
Research Support/ EPRI	17,227	17,227	0
Total	$40,127	$37,837	$2,290

generating stations and also to complexes requiring a central energy supply located away from existing generating stations.

Advanced Space Conditioning - work toward increasing the efficiency of space conditioning equipment and providing customers with cost-effective options for shifting electric space cooling loads from on-peak to off-peak periods.

On-Site Generation and Cogeneration Project - explore and develop various small generating technologies which can provide an alternative to traditional electric service.

b. **Storage and Energy Management Technologies**

Electric Transportation - accelerate development of commercial electrically powered transportation involving prototype vehicle evaluations, development and evaluation of advanced vehicle/battery concepts, formulation of commercialization strategy, and electrified roadway demonstrations.

PSD states that these are marketing programs designed to develop additional sales, build load, and to avoid losing sales to self-generation. PSD believes that marketing and load building programs are very short-sighted and, while they take advantage of current excess capacity, promote usage that ultimately needs to be curtailed. In addition, PSD is concerned that Edison's use of ratepayer monies for the development of these programs will primarily benefit its investors, either through the utility company or its unregulated subsidiaries. Finally, PSD argues that Edison's participation in the electric transportation project should be through the Electric Power Research Institute (EPRI), since it will be doing work of a parallel nature.

Another area in which PSD recommends a reduction in Edison's budget is the high performance peaking technologies

Besides its differences with Edison on specific RD&D programs, PSD has addressed four policy issues: (1) ratepayer benefits from EPRI dues, (2) approval of RD&D program changes in excess of $500,000, (3) establishment of a one way balancing account for RD&D funds, (4) coordination of large RD&D programs with other California utilities, and (5) inclusion of all RD&D expenses in the same account.

While PSD has accepted Edison's request for full funding of EPRI dues, it is concerned about EPRI's apparent shift in research direction and whether ratepayer benefits from EPRI exceed contributions. First, PSD recommends that Edison in its next general rate case be required to provide a comprehensive assessment of the benefits from EPRI. Second, PSD is concerned that the labels (creating the future, building markets, reducing risks, and controlling costs) used by EPRI for its program expenditures for 1987-1989 seems to indicate a shift in research direction. This leads PSD to recommend that if a single proceeding is established to investigate all utility RD&D programs EPRI, its orientation, and ratepayer benefits should be included.

Next, PSD states that it does not wish to deter Edison from making shifts in its RD&D budget and priorities when appropriate. However, PSD believes that it and the Commission should be given sufficient information to allow oversight of Edison's decisions. Because PSD feels that it was not provided detailed information concerning shifts in Edison's RD&D budget and priorities (see discussion below), it recommends that Edison receive approval before shifting funds. Specifically, PSD proposes that an advice letter procedure be required to shift funds between programs in excess of $500,000 or 50% of the budget, whichever is less. In addition, PSD recommends that a one way balancing account be imposed to insure that RD&D funding is spent on RD&D projects.

PSD is also concerned with the amount of coordination among California utilities in their RD&D efforts. While PSD

project. PSD recommends that Edison's budget for this project be cut by $225,000 by combining the monitoring research activities.

PSD also disagrees with Edison's shift in priorities from developing new resources to consuming existing conventional resources at an expanding rate. Edison reduced its original budget for the alternate fuels, occupational and community safety, and advanced energy conversion programs by $2.4 million and other programs by $2.5 million. These reductions were made to provide funding for the competing for the customer and load control/customer interface programs and the electric transportation project without increasing the overall RD&D budget. PSD recommends reinstatement of $1.5 million in program cuts for the alternate fuels, occupational and community safety, and advanced energy conversion programs.

The following table summarizes Edison's and PSD's recommended RD&D program expenditures.

strongly supports our statements in D.87-07-021 that there is a need to ensure that RD&D is coordinated and cost-effective to ratepayers, its recommendation in this proceeding is that Edison avail itself of existing opportunities for coordination.

Therefore, PSD recommends that effective January 1, 1989, Edison not be permitted to undertake large demonstration projects (exceeding $5 million on an aggregate rather than annual basis) having statewide benefits without presenting evidence that it was reviewed by the California Utility Research Council (Council). Although this is not intended to give the Council a veto over these projects, PSD states that Edison should receive an endorsement from the Council.

PSD's last policy issue concerns Edison's accounting practices for RD&D expenses. To simplify record keeping PSD recommends that all RD&D expenses be accounted for in Edison's A&G account 930.2.

As a final item, PSD has expressed considerable displeasure with Edison's handling of program revisions. PSD argues that after Edison's application was filed it made dramatic changes in the RD&D program without informing the Commission or the PSD, except in a cursory fashion. Because of this, PSD claims that it was unable to make a detailed review of the recent modifications. PSD states that after Edison's witness testified that he could not think of any other significant changes in the RD&D budget, Edison less than three weeks later:

1. Added an entirely new program area called competing for the customer which was given the second highest priority and a budget of $2.5 million.

2. Decreased the storage and energy management technologies program by $1.5 million.

3. Reduced the alternate fuels program by $1.1 million.

Comparison of Edison and PSD RD&D Expenditures (1986 Dollars)

Program Area	Edison	PSD	Edison Exceeds PSD
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Total	$40,127	$37,837	$2,290

4. Reduced the renewable energy conversion program by $570,000.

In addition, PSD points out that less than 24 hours prior to Edison's witness testifying to these revisions, PSD received additional prepared testimony concerning a multi-year, multi-million dollar program to develop an electric vehicle. PSD does not believe there is any reason for Edison's actions and, in fact, is unaware of any other area in this general rate case where major updates were not provided well in advance.

2. <u>The Organizing Committee for the California Institute for Energy Efficiency's (Institute) Position</u>

The Institute is proposed as a university-based research institution with participation by California utilities, our Commission, the CEC, and others. The Council has reviewed a number of Institute-proposed projects for medium-to long-term, end-use research with statewide significance. These would be co-funded by California utilities, State agencies, and others. While not an active participant in the proceeding, the Institute did file a brief. The following summarizes its position as contained in that brief:

1. There is a need for increased utility emphasis on long-term, end-use RD&D that is consistent with the utility's resource plan and coordinated with other California utilities and experienced research organizations.

2. The Institute is the appropriate mechanism for implementing the objectives above.

3. Edison should be authorized and encouraged to participate in the Institute, as part of its RD&D and related energy management and end-use load research activities, at a minimum level of $1 million to $2 million per year.

Besides its differences with Edison on specific RD&D programs, PSD has addressed four policy issues: (1) ratepayer benefits from EPRI dues, (2) approval of RD&D program changes in excess of $500,000, (3) establishment of a one way balancing account for RD&D funds, (4) coordination of large RD&D programs with other California utilities, and (5) inclusion of all RD&D expenses in the same account.

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PSD is also concerned with the amount of coordination among California utilities in their RD&D efforts. While PSD

3. Edison's Position

In support of its competing for the customer program Edison states that in late 1986 it acted to refocus the direction of its research programs to provide customers with a better value for their energy dollar. Greater emphasis is now being placed on technologies that will help customers reduce their energy bills through improved efficiency. Through this program Edison proposes to:

1. Provide existing customers with cost effective technologies to shift a portion of their load from peak to off-peak periods to take advantage of lower time-of-use rates.

2. Operate the existing generating stations at higher loads and efficiencies resulting in lower costs to existing customers.

3. Develop high efficiency, low cost on site generators which contributes to the CEC's goal of greater efficiency and cost stability and could result in substantial royalty revenues being flowed through to ratepayers.

Edison justifies its electric transportation project by stating that it will improve system load factor, reduce the amount of economy energy rejected at minimum load, and increase the operating efficiency of Edison's generating units. In addition, Edison estimates that with the technology that could be achieved in the next three years (150-mile vehicle range), its off-peak load would increase by 600 MW compared to its 2000 MW of excess base load during minimum load conditions. This, Edison argues, will help stabilize electric rates and benefit all customers, not just the owners of electric vehicles.

The last project which PSD opposes is in the area of high performance peaking technologies. Edison points out that this project involves the transfer of information on new technologies to

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3. Reduced the alternate fuels program by $1.1 million.

other Edison departments and the monitoring or keeping abreast of other research organizations, is cost-effective and eliminates duplication. Edison believes that PSD's recommendation to combine monitoring efforts of different technologies to reduce cost is cosmetic; the activity must still be performed by the research scientist with expertise in the individual technology.

Finally, on the issue of program funding, Edison agrees with PSD's position that $1.5 million in funding for the alternate fuels, occupational and community safety, and advanced energy conversion programs should be restored.

In response to the policy issues that were raised by PSD and the Institute, Edison states that:

1. It has consistently adopted a research budget equal to or greater than the authorized Commission funding for RD&D and intends to use funds committed to RD&D on RD&D projects.

2. All future RD&D expenditures will be accounted for in A&G account 930.2.

3. It has participated in a review of the Institute's proposed projects through the Council and that some of these projects will receive funding. However, the Institute's recommendation is inconsistent with Edison's competitive bidding policies.

4. Discussion

PSD criticizes the competing for the customer program and the electric transportation project because they are marketing and load building programs, primarily intended to benefit Edison's investors. Because PSD was not provided sufficient time to review these programs, we feel the true benefits of providing customers with the opportunity to shift loads and reduce their overall energy bills were overlooked. This coupled with Edison's ability to operate its generating stations at higher loads and efficiencies justifies these types of programs.

4. Reduced the renewable energy conversion program by $570,000.

In addition, PSD points out that less than 24 hours prior to Edison's witness testifying to these revisions, PSD received additional prepared testimony concerning a multi-year, multi-million dollar program to develop an electric vehicle. PSD does not believe there is any reason for Edison's actions and, in fact, is unaware of any other area in this general rate case where major updates were not provided well in advance.

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1. There is a need for increased utility emphasis on long-term, end-use RD&D that is consistent with the utility's resource plan and coordinated with other California utilities and experienced research organizations.
2. The Institute is an appropriate mechanism for implementing the objectives above.
3. Edison should be authorized and encouraged to participate in the Institute, as part of its RD&D and related energy management and end-use load research activities, at a minimum level of $1 million to $2 million per year.

While Edison's proposed budget for the competing for the customer program should be authorized, we feel that the electric transportation project should not be approved as requested. Edison has not demonstrated that this project is unique for Edison or, more importantly, that similar benefits cannot be obtained from EPRI, which is performing work of a parallel nature. However, we will authorize Edison to include $100,000 in its budget to monitor the work of EPRI and other organizations in this area.

PSD's other program funding recommendations concern the high performance peaking technologies project and the alternate fuels, occupational and community safety, and advanced energy conversion programs. With respect to the high performance peaking technologies project, we find Edison's justification satisfactory and will not cut its budgeted amount.

For the remaining programs at issue, both PSD and Edison recommend that $1.5 million be restored to Edison's RD&D budget. Edison made these cuts to partially offset increases in other areas. Our review of the alternate fuels, occupational and community safety, and advanced energy conversion programs indicates that they are generally beneficial to the ratepayers. Because these are lower priority programs we will authorize Edison to restore only $900,000 in funding for these three programs.

At ALJ Ferraro's direction Edison was permitted to revise its RD&D showing to reflect the electric transportation project, but not allowed to increase its overall budget request from that contained in its application. As a result of this ruling, Edison identified the occupational and community safety and natural resources management programs as the lowest priority and reduced their budget commensurate with the increase for the electric transportation project. Since neither Edison or PSD made a recommendation with respect to the natural resources management program, we will not restore funding for this low priority program.

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In support of its competing for the customer program Edison states that in late 1986 it acted to refocus the direction of its research programs to provide customers with a better value for their energy dollar. Greater emphasis is now being placed on technologies that will help customers reduce their energy bills through improved efficiency. Through this program Edison proposes to:

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The last project which PSD opposes is in the area of high performance peaking technologies. Edison points out that this project involves the transfer of information on new technologies to other Edison departments and the monitoring or keeping abreast of

Finally, consistent with prior general rate decisions for Edison and other energy utilities, we will reflect Edison's actual billing for EPRI dues of $14.7 million. This is an increase of approximately $247,000 over Edison's estimated dues for 1988.

The next area we will address is the policy issues raised by the parties. In D.87-07-021 we expressed our interest in pursuing a generic proceeding that would consider the merits of all energy utility RD&D programs on a consolidated basis. In R.87-10-013 we directed Edison, SoCal, PG&E, and SDG&E to comment on the establishment of a generic proceeding for approval of all RD&D budgets. While it will take time to fully coordinate the budgets of these utilities, EPRI, and the Gas Research Institute (GRI), the benefits of a more cost-effective RD&D program should be well worth the effort.

Currently the four major energy utilities that we regulate spend nearly $100 million annually on RD&D programs, including dues to EPRI and GRI. Since this is a significant expenditure of ratepayer funds we believe that a simultaneous review of each utility's RD&D program will reduce duplication, provide uniform policy direction, and increase the cost-effectiveness of utility run RD&D programs as well as EPRI and GRI benefits.

Although a consolidated proceeding will provide the mechanism through which these accomplishments can be made, it in itself is not the solution. For us to have a record from which to direct the utilities, it is necessary to have an organization such as the Council assist us. The Council was created in response to P.U. Sections 9201 through 9203. These code sections require us and the CEC to meet annually with representatives from the four energy utilities named above. In addition, representatives of municipal utilities, public utility districts, EPRI, GRI, and consumer or ratepayer organizations may be invited. As stated in P.U. Section 9203:

other research organizations, is cost-effective and eliminates duplication. Edison believes that PSD's recommendation to combine monitoring efforts of different technologies to reduce cost is cosmetic; the activity must still be performed by the research scientist with expertise in the individual technology.

Finally, on the issue of program funding, Edison agrees with PSD's position that $1.5 million in funding for the alternate fuels, occupational and community safety, and advanced energy conversion programs should be restored.

In response to the policy issues that were raised by PSD and the Institute, Edison states that:

1. It has consistently adopted a research budget equal to or greater than the authorized Commission funding for RD&D and intends to use funds committed to RD&D on RD&D projects.

2. All future RD&D expenditures will be accounted for in A&G account 930.2.

3. It has participated in a review of the Institute's proposed projects through the Council and that some of these projects will receive funding. However, the Institute's recommendation is inconsistent with Edison's competitive bidding policies.

4. Discussion

PSD criticizes the competing for the customer program and the electric transportation project because they are marketing and load building programs, primarily intended to benefit Edison's investors. Because PSD was not provided sufficient time to review these programs, we feel the true benefits of providing customers with the opportunity to shift loads and reduce their overall energy bills were overlooked. This coupled with Edison's ability to operate its generating stations at higher loads and efficiencies justifies these types of programs.

> "The purpose of the meeting shall be to work towards achieving all of the following goals:
> (a) Promoting consistency of research, development, and demonstration programs with state energy policy.
> (b) Preventing unnecessary duplicative research, development, and demonstration efforts.
> (c) Where appropriate, freely exchanging information related to research, development, and demonstration projects.
> (d) Identifying opportunities for joint funding of research, development, and demonstration projects."

With this mandate from the legislature we expect that the Council will develop a report which addresses the items listed above and can be used in our generic proceeding as a guide to establish each utility's RD&D budget. It is not our intent to control the Council or give it control over the RD&D budgets we authorize, but rather to work with the Council to insure that RD&D expenditures are made in the best interest of utility ratepayers.

To accomplish this we will direct Edison, SoCal, PG&E, SDG&E, and PSD to work toward the objectives outlined above. In addition, we expect Edison, SoCal, PG&E, and SDG&E to set forth in their future RD&D budget requests how their proposed budgets meet the guidelines established in prior Commission decisions and the objectives of the Council. We want to emphasize that we are committed to this coordination effort and expect the utilities and PSD to inform us of any problems which would impede its implementation.

With the establishment of R.87-10-013 we will not adopt PSD's recommendation requiring Edison to receive approval of program changes. However, Edison will be held accountable in either the generic proceeding or its next general rate case, whichever comes first, for any changes made in its RD&D programs.

We also feel that in light of the generic RD&D proceeding it is premature for us to address specific recommendations

While Edison's proposed budget for the competing for the customer program should be authorized, we feel that the electric transportation project should not be approved as requested. Edison has not demonstrated that this project is unique for Edison or, more importantly, that similar benefits cannot be obtained from EPRI, which is performing work of a parallel nature. However, we will authorize Edison to include $100,000 in its budget to monitor the work of EPRI and other organizations in this area.

PSD's other program funding recommendations concern the high performance peaking technologies project and the alternate fuels, occupational and community safety, and advanced energy conversion programs. With respect to the high performance peaking technologies project, we find Edison's justification satisfactory and will not cut its budgeted amount.

For the remaining programs at issue, both PSD and Edison recommend that $1.5 million be restored to Edison's RD&D budget. Edison made these cuts to partially offset increases in other areas. Our review of the alternate fuels, occupational and community safety, and advanced energy conversion programs indicates that they are generally beneficial to the ratepayers. Because these are lower priority programs we will authorize Edison to restore only $900,000 in funding for these three programs.

At ALJ Ferraro's direction Edison was permitted to revise its RD&D showing to reflect the electric transportation project, but not allowed to increase its overall budget request from that contained in its application. As a result of this ruling, Edison identified the occupational and community safety and natural resources management programs as the lowest priority and reduced their budget commensurate with the increase for the electric transportation project. Since neither Edison or PSD made a recommendation with respect to the natural resources management program, we will not restore funding for this low priority program.

concerning coordination of RD&D programs, benefits from EPRI dues, and funding of Institute programs. In the interim, we encourage Edison to coordinate its end-use research activities with other utilities and the Institute. We also expect Edison to work with the Institute in resolving any difficulities surrounding Edison's competitive bidding policies for RD&D.

The last policy issues which were raised concern PSD's recommendations to establish a one way balancing for RD&D funds and to record all RD&D expenses in account 930.2. Because of the unique nature of RD&D, we will adopt a one way balancing account for Edison to insure that RD&D funds are spent on RD&D programs. This is consistent with our discussion in D.87-07-021 in which a one way balancing account was adopted for PG&E. Additionally, to facilitate the analysis of RD&D expenditures, we will adopt PSD's recommendation that all RD&D expenses be accounted for in Edison's A&G account 930.2.

Finally, while Edison's presentation in this proceeding was generally very professional, we consider its conduct in the RD&D area unacceptable. Edison's attempt to revise its RD&D showing at the public hearings in Pomona undermines the rate case plan.

At the Pomona public hearings Edison in its opening statement and without any evidentiary basis proposed a new multi-year, multi-million dollar electric transportation project. While it was thoughtful of Edison to inform the public of its new program, the public hearings were not the proper time or place to initiate such a request. Not only does the rate case plan not provide for this type of presentation at public hearings, but Edison had just revised its RD&D budget seven days earlier without any mention of the electric transportation project. Edison is put on notice that it should take steps to insure that this does not reoccur and that any future late additions or substantial changes will simply not be considered.

Finally, consistent with prior general rate decisions for Edison and other energy utilities, we will reflect Edison's actual billing for EPRI dues of $14.7 million. This is an increase of approximately $247,000 over Edison's estimated dues for 1988.

The next area we will address is the policy issues raised by the parties. In D.87-07-021 we expressed our interest in pursuing a generic proceeding that would consider the merits of all energy utility RD&D programs on a consolidated basis. In R.87-10-013 we directed Edison, SoCal, PG&E, and SDG&E to comment on the establishment of a generic proceeding for approval of all RD&D budgets. While it will take time to fully coordinate the budgets of these utilities, EPRI, and the Gas Research Institute (GRI), the benefits of a more cost-effective RD&D program should be well worth the effort.

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Although a consolidated proceeding will provide the mechanism through which these accomplishments can be made, it in itself is not the solution. For us to have a record from which to direct the utilities, it is necessary to have an organization such as the Council assist us. The Council was created in response to P.U. Sections 9201 through 9203. These code sections require us and the CEC to meet annually with representatives from the four energy utilities named above. In addition, representatives of municipal utilities, public utility districts, EPRI, GRI, and consumer or ratepayer organizations may be invited. As stated in P.U. Section 9203:

H. Productivity

A new area which has been addressed in recent general rate cases is the use of econometric models to measure the productivity for total utility operating expenses. These models relate changes in a utility's level of production, to changes in the level of required resources. The percentage change in the productivity index from one period to the next measures the savings due to productivity.

Both Edison and PSD developed econometric models to evaluate the the productivity savings contained in Edison's test year operating expense level. Edison, based on its total factor productivity (TFP) model, determined that no adjustment to its requested expense level was warranted. PSD concluded from its multi-factor productivity model that Edison's requested operating expense should be reduced by $211.5 million to adequately reflect productivity savings.

Edison's model estimated productivity for the historical period 1976-1985 and the projected years 1986-1988. Over the 13 year study period, Edison's TFP index increased at an average rate of 1.6% per year as compared to the annual rate of more than 2% reflected in Edison's test year expense. Although Edison believes that the TFP index confirms the reasonableness of its test year operating expense, Edison states that it is an inexact measure of performance. Other factors besides productivity affect the year to year change in the index, such as variations in the availability of hydro power. Additionally, Edison argues that a productivity index should not be used as a rate case adjustment mechanism because it double counts productivity gains and is applied to only one segment of utility costs, operating expense.

Because a productivity index measures productivity already embedded in Edison's rate case cost estimates, Edison states that any adjustment to expense based on an index will be double-counting. Next, Edison points out that over the past

"The purpose of the meeting shall be to work towards achieving all of the following goals:

(a) Promoting consistency of research, development, and demonstration programs with state energy policy.

(b) Preventing unnecessary duplicative research, development, and demonstration efforts.

(c) Where appropriate, freely exchanging information related to research, development, and demonstration projects.

(d) Identifying opportunities for joint funding of research, development, and demonstration projects."

With this mandate from the legislature we expect that the Council will develop a report which addresses the items listed above and can be used in our generic proceeding as a guide to establish each utility's RD&D budget. It is not our intent to control the Council or give it control over the RD&D budgets we authorize, but rather to work with the Council to insure that RD&D expenditures are made in the best interest of utility ratepayers.

To accomplish this we will direct Edison, SoCal, PG&E, SDG&E, and PSD to work toward the objectives outlined above. In addition, we expect Edison, SoCal, PG&E, and SDG&E to set forth in their future RD&D budget requests how their proposed budgets meet the guidelines established in prior Commission decisions and the objectives of the Council. We want to emphasize that we are committed to this coordination effort and expect the utilities and PSD to inform us of any problems which would impede its implementation.

With the establishment of R.87-10-013 we will not adopt PSD's recommendation requiring Edison to receive approval of program changes. However, Edison will be held accountable in either the generic proceeding or its next general rate case, whichever comes first, for any changes made in its RD&D programs.

decade, in response to higher fossil fuel prices, it has moved from a reliance on conventional oil and gas fired generation to the use of a variety of technologies, including nuclear, hydroelectric, and renewable energy sources. Because the index shows overall productivity gains, no consideration is given to the fact that fuel savings outweigh the increased use of capital and labor. Accordingly, it is inappropriate to apply a utility-wide measure to only one segment of costs such as operating expense, since productivity savings do not occur evenly.

Edison is critical of PSD's productivity model for the reasons stated above and because it is difficult to interpret, exceedingly complex, subject to error, and does not account for changes in Edison's operating environment. Also, Edison believes that PSD's use of the ECAC fuel and purchased power forecast to determine operating expense from its model is inappropriate. PSD's model predicts fuel and purchased power will be 54% of variable costs in 1988 as compared to 58% for recorded 1986, but Edison states that PSD chose to use the ECAC forecast which is 64% of variable costs.

Finally, Edison claims that PSD's recommendation is not plausible and creates a perverse incentive. First, PSD's econometric forecast results in an unrealistically low level of O&M expense. The O&M expense recommendation of PSD is $122 million below actual 1986 and significantly lower than the expense estimates of PSD's results of operation witnesses. Second, the more productive a utility has been historically, the greater the reduction in the recommended level of operating expense. A utility which has been productive will receive less money to operate than a utility which has been less or not productive.

In developing its model PSD investigated the historical relationship between five input variables (fuel, purchased power, capital, labor, and materials) and Edison's output (kilowatthour sales). The relationship between the changes of the inputs and the

All expenditures for program changes found unreasonable will be deleted from the one-way balancing account retroactively.

We also feel that in light of the generic RD&D proceeding it is premature for us to address specific recommendations concerning coordination of RD&D programs, benefits from EPRI dues, and funding of Institute programs. In the interim, we encourage Edison to coordinate its end-use research activities with other utilities and the Institute. We also expect Edison to work with the Institute in resolving any difficulities surrounding Edison's competitive bidding policies for RD&D.

The last policy issues which were raised concern PSD's recommendations to establish a one way balancing for RD&D funds and to record all RD&D expenses in account 930.2. Because of the unique nature of RD&D, we will adopt a one way balancing account for Edison to insure that RD&D funds are spent on RD&D programs. This is consistent with our discussion in D.87-07-021 in which a one way balancing account was adopted for PG&E. Additionally, to facilitate the analysis of RD&D expenditures, we will adopt PSD's recommendation that all RD&D expenses be accounted for in Edison's A&G account 930.2.

Finally, while Edison's presentation in this proceeding was generally very professional, we consider its conduct in the RD&D area unacceptable. Edison's attempt to revise its RD&D showing at the public hearings in Pomona undermines the rate case plan.

At the Pomona public hearings Edison in its opening statement and without any evidentiary basis proposed a new multi-year, multi-million dollar electric transportation project. While it was thoughtful of Edison to inform the public of its new program, the public hearings were not the proper time or place to initiate such a request. Not only does the rate case plan not provide for this type of presentation at public hearings, but Edison had just revised its RD&D budget seven days earlier without changes of the output over the historical period defined Edison's historical productivity and formed the basis for PSD's projection of productivity in the test period. PSD observed an annual productivity growth over the recorded period of 2.4% and projected a productivity growth of 3.4% for 1988. Based on its projected productivity growth, PSD recommends that Edison's requested O&M expense be reduced by an additional $115.8 million over the recommendations of PSD's results of operation witnesses.

Finally, after analyzing Edison's TFP model PSD concluded that with some minor refinements it is the same model used by PSD in PG&E's general rate case and rejected in D.86-12-095.

In arriving at a reasonable level of operating expense for utilities we typically consider productivity gains due to changes in technology, economies of scale, and improved efficiency. However, it is difficult to quantify the impact these have in the test year. While individual witnesses for Edison and PSD, depending on their estimating methodology, either directly or indirectly reflected productivity gains in their test year estimates, until recently no attempt was made to determine how these compared to recorded productivity gains for total operating expense. The productivity models of Edison and PSD do this by analyzing recorded productivity gains in order to forecast productivity gains in the test year. From the TFP analysis, Edison concluded that its requested operating expense level projected productivity gains in excess of historical gains and should be adopted. PSD's analysis led it to recommend an additional $115.8 million reduction in Edison's requested level of operating expense.

We feel that a comparison of recorded versus projected productivity gains is useful. However, due to the complexities in and the divergent results of the models, their application will be limited to determining a range of productivity gains to be adopted in the test year. As defined by these models, the range is between 1.6% and 3.4%. Since our adopted operating expense, as discussed any mention of the electric transportation project. Edison is put on notice that it should take steps to insure that this does not reoccur and that any future late additions or substantial changes will simply not be considered.

H. Productivity

A new area which has been addressed in recent general rate cases is the use of econometric models to measure the productivity for total utility operating expenses. These models relate changes in a utility's level of production, to changes in the level of required resources. The percentage change in the productivity index from one period to the next measures the savings due to productivity.

Both Edison and PSD developed econometric models to evaluate the the productivity savings contained in Edison's test year operating expense level. Edison, based on its total factor productivity (TFP) model, determined that no adjustment to its requested expense level was warranted. PSD concluded from its multi-factor productivity model that Edison's requested operating expense should be reduced by $211.5 million to adequately reflect productivity savings.

Edison's model estimated productivity for the historical period 1976-1985 and the projected years 1986-1988. Over the 13 year study period, Edison's TFP index increased at an average rate of 1.6% per year as compared to the annual rate of more than 2% reflected in Edison's test year expense. Although Edison believes that the TFP index confirms the reasonableness of its test year operating expense, Edison states that it is an inexact measure of performance. Other factors besides productivity affect the year to year change in the index, such as variations in the availability of hydro power. Additionally, Edison argues that a productivity index should not be used as a rate case adjustment mechanism because it double counts productivity gains and is applied to only one segment of utility costs, operating expense.

in other sections of this decision, incorporates productivity gains of approximately 2.4%, which is slightly below the middle of the range, we will increase it by an additional 0.2%. This adjustment results in an additional reduction in Edison's operating expenses of $33.6 million. We believe this is warranted to put Edison in a posture to respond to an increasing level of competition.

I. Employee Compensation

As part of its review of Edison's results of operations, PSD performed an analysis of Edison's employee compensation levels. Based on this study PSD determined that administrative, professional, and supervisory (APS) employees are paid 10.2 percent over the prevailing market and that Edison's ratemaking payroll expense should be reduced by $19.7 million.

PSD's recommendation was developed from a variety of employee compensation surveys and related data obtained from Edison. The two key surveys used in PSD's evaluation of APS salaries were Edison's 1986 APS salary survey conducted by Organization Resource Counsellors, Inc. and SoCal's 1986 survey of executive, administrative, professional an supervisory positions, conducted by Sibson & Company, Inc..

Edison objects to PSD's use of these surveys for a number of reasons:

1. The surveys were designed 15 years ago for the purpose of tracking labor market salary movement.

2. The same jobs that were included in the original surveys are still used even though many are now vacant and certain areas are not represented.

3. Sample sizes contained in the surveys are too limited, introducing the potential for bias.

4. Data from nine of the companies is common to both surveys.

Because a productivity index measures productivity already embedded in Edison's rate case cost estimates, Edison states that any adjustment to expense based on an index will be double-counting. Next, Edison points out that over the past decade, in response to higher fossil fuel prices, it has moved from a reliance on conventional oil and gas fired generation to the use of a variety of technologies, including nuclear, hydroelectric, and renewable energy sources. Because the index shows overall productivity gains, no consideration is given to the fact that fuel savings outweigh the increased use of capital and labor. Accordingly, it is inappropriate to apply a utility-wide measure to only one segment of costs such as operating expense, since productivity savings do not occur evenly.

Edison is critical of PSD's productivity model for the reasons stated above and because it is difficult to interpret, exceedingly complex, subject to error, and does not account for changes in Edison's operating environment. Also, Edison believes that PSD's use of the ECAC fuel and purchased power forecast to determine operating expense from its model is inappropriate. PSD's model predicts fuel and purchased power will be 54% of variable costs in 1988 as compared to 58% for recorded 1986, but Edison states that PSD chose to use the ECAC forecast which is 64% of variable costs.

Finally, Edison claims that PSD's recommendation is not plausible and creates a perverse incentive. First, PSD's econometric forecast results in an unrealistically low level of O&M expense. The O&M expense recommendation of PSD is $122 million below actual 1986 and significantly lower than the expense estimates of PSD's results of operation witnesses. Second, the more productive a utility has been historically, the greater the reduction in the recommended level of operating expense. A utility which has been productive will receive less money to operate than a utility which has been less or not productive.

Additionally, Edison argues that PSD's analysis contains significant technical errors which render its conclusions invalid, and inappropriate as the basis for an adjustment of estimated payroll expense. Edison identifies the following as errors in PSD's analysis:

1. The impact of employee turnover, which involves such considerations as stability of the work force, average experience level, individual employee performance, seniority, and Edison's investment in training and development, is ignored.

2. PSD did not consider the affects compensation levels have on Eddison's ability to attract qualified and experienced employees.

3. The nature of Edison's organization, its size, the characteristics of its service territory, its customer mix, and the methods used to provide service were not included.

4. PSD failed to evaluate the relationship between APS pay levels and pay levels for bargaining unit employees.

5. The survey data was improperly weighted.

While Edison did not attempt to evaluate employee compensation based on salary surveys, it did make a comparison of payroll to revenue. This approach provides a quick indicator of overall payroll costs relative to a selected marketplace or industry. Using the 1986 executive compensation survey conducted annually by Sibson & Company, Inc., Edison concluded that for 108 companies the average percentage of payroll to revenues is 12.44% which compares favorably to Edison's 12.07%.

Edison also adjusted PSD's analysis to correct for the improper weighting of jobs and the double counting of companies. PSD's overpayment of APS employees is reduced from 9.2% to 7.5% based on Edison's calculations.

In developing its model PSD investigated the historical relationship between five input variables (fuel, purchased power, capital, labor, and materials) and Edison's output (kilowatthour sales). The relationship between the changes of the inputs and the changes of the output over the historical period defined Edison's historical productivity and formed the basis for PSD's projection of productivity in the test period. PSD observed an annual productivity growth over the recorded period of 2.4% and projected a productivity growth of 3.4% for 1988. Based on its projected productivity growth, PSD recommends that Edison's requested O&M expense be reduced by an additional $115.8 million over the recommendations of PSD's results of operation witnesses.

Finally, after analyzing Edison's TFP model PSD concluded that with some minor refinements it is the same model used by PSD in PG&E's general rate case and rejected in D.86-12-095.

In arriving at a reasonable level of operating expense for utilities we typically consider productivity gains due to changes in technology, economies of scale, and improved efficiency. However, it is difficult to quantify the impact these have in the test year. While individual witnesses for Edison and PSD, depending on their estimating methodology, either directly or indirectly reflected productivity gains in their test year estimates, until recently no attempt was made to determine how these compared to recorded productivity gains for total operating expense. The productivity models of Edison and PSD do this by analyzing recorded productivity gains in order to forecast productivity gains in the test year.

Edison concluded from its TFP analysis that its requested operating expense level reflected historical productivity gains and should be adopted. PSD's analysis led it to recommend an additional $115.8 million reduction in Edison's requested level of operating expense. Compared to Edison's original O&M expense level request of $1,374 million PSD's recommended operating expense

Finally, Edison cites D.86-12-095 for PG&E in which management salary levels exceeded the utility industry average by approximately 8% as recognition that paying a small premium over market benefits the ratepayer as well as the shareholder.

In support of its recommendation, PSD states that its study of employee compensation focused on the market from which Edison draws it labor, categorized payroll data by type of employee, and relied on five independent salary surveys. PSD grouped Edison's work force into five categories: (1) executive, (2) APS, (3) clerical, (4) physical, and (5) technical. PSD found Edison's executive, clerical and physical salaries to be reasonably in accord with market salary levels, and did not recommend an expense reduction for those categories. Since there was insufficient data available for Edison's technical work force, PSD made no ratemaking recommendation for that category. For APS employees, although a benefit comparison was not made, PSD concluded that salary levels are excessive and recommended a 9.2% or $19.7 million reduction in labor expense for this category.

In concluding, PSD states that it is puzzled by Edison's argument that the salary surveys used by PSD are inappropriate for evaluating the reasonableness of compensation to APS employees. PSD wonders why these salary surveys are commissioned if they should not be used to study salaries.

We believe PSD's analysis in this proceeding is a significant improvement over its PG&E proposal. However, before it can be used to judge the reasonableness of Edison's level of payroll expenses, there are further refinements that should be considered. First, comparisons should either be made on a total compensation basis or adjusted to reflect the employees' benefit package. Second, in addition to point comparisons based on averages information indicating the range of data should be provided. Lastly, Edison's criticisms concerning sample sizes and level, including its productivity adjustment, reflects additional productivity gains of $317 million.

We feel that a comparison of recorded versus projected productivity gains is useful. However, due to the complexities in and the divergent results of the models, their application will be limited to determining a range of productivity gains to be adopted in the test year. As defined by these models, the range is between 1.6% and 3.4%. Since our adopted operating expense level of $1,205 million without a productivity adjustment incorporates productivity gains of 2.56%, approximately the middle of the range, we will increase it to a level of 2.75%. This adjustment results in an additional reduction in Edison's operating expenses of $33.5 million. We believe this is warranted to put Edison in a posture to respond to an increasing level of competition.

I. <u>Employee Compensation</u>

As part of its review of Edison's results of operations, PSD performed an analysis of Edison's employee compensation levels. Based on this study PSD determined that administrative, professional, and supervisory (APS) employees are paid 10.2 percent over the prevailing market and that Edison's ratemaking payroll expense should be reduced by $19.7 million.

PSD's recommendation was developed from a variety of employee compensation surveys and related data obtained from Edison. The two key surveys used in PSD's evaluation of APS salaries were Edison's 1986 APS salary survey conducted by Organization Resource Counsellors, Inc. and SoCal's 1986 survey of executive, administrative, professional an supervisory positions, conducted by Sibson & Company, Inc..

Edison objects to PSD's use of these surveys for a number of reasons:

1. The surveys were designed 15 years ago for the purpose of tracking labor market salary movement.

the duplication of jobs and companies in the survey data should be addressed.

Our objective is to ensure that ratepayers are not burdened with paying for employee compensation levels beyond that which is necessary for Edison to provide safe reliable service at reasonable rates. This type of evaluation is difficult because of the subjectiveness involved in quantifying the variables used. To minimize this, we expect both PSD and Edison in future general rate proceedings to develop an agreed upon data base for judging the reasonableness of employee compensation levels. For this proceeding, we find Edison's justification for its APS compensation levels reasonable.

J. Affiliated Transactions

PSD raised five issues concerning the affiliated relationships of Edison and its subsidiary companies. In this proceeding Edison and PSD have come to agreement on two of these issues: gains on sales of utility assets to affiliates and net income of utility-related subsidiaries. For these issues Edison and PSD recommend that:

1. All gains on sales of utility assets to nonutility subsidiaries should be recorded above-the-line at market value.

2. Utility-related subsidiaries should be treated, for ratemaking purposes, as utility departments and all transfers of utility assets to those subsidiaries should be at book value.

3. Net income from utility-related subsidiaries should be recorded above-the-line.

Edison and PSD are also in agreement that a $1.0 million increase in Edison's test year estimate of other operating revenues should be adopted to reflect the impact of these recommendations.

2. The same jobs that were included in the original surveys are still used even though many are now vacant and certain areas are not represented.

3. Sample sizes contained in the surveys are too limited, introducing the potential for bias.

4. Data from nine of the companies is common to both surveys.

Additionally, Edison argues that PSD's analysis contains significant technical errors which render its conclusions invalid, and inappropriate as the basis for an adjustment of estimated payroll expense. Edison identifies the following as errors in PSD's analysis:

1. The impact of employee turnover, which involves such considerations as stability of the work force, average experience level, individual employee performance, seniority, and Edison's investment in training and development, is ignored.

2. PSD did not consider the affects compensation levels have on Edison's ability to attract qualified and experienced employees.

3. The nature of Edison's organization, its size, the characteristics of its service territory, its customer mix, and the methods used to provide service were not included.

4. PSD failed to evaluate the relationship between APS pay levels and pay levels for bargaining unit employees.

5. The survey data was improperly weighted.

PSD's remaining three issues address royalty payments from subsidiaries. For these issues PSD recommends that subsidiaries pay:

1. A royalty or affiliate payment of 5% of gross revenues.

2. A markup royalty of 10% for services provided by the utility.

3. A royalty upon the transfer of an employee from the utility to the subsidiary equal to 50% of the employee's annual salary.

The three issues above were also addressed in A.87-05-007, Edison's request to establish a holding company structure. In A.87-05-007 Edison and PSD submitted a joint exhibit agreeing to: (1) the markup royalty for services provided by the utility and (2) the guidelines for utility employee transfers to affiliates. As stated in the joint exhibit a 5% markup on fully loaded labor costs will be billed to nonutility affiliates for the use of Edison employees. The joint exhibit also sets forth the following guidelines for the transfer of utility employees to affiliates:

1. The staffing of the nonregulated affiliates will not be to the detriment of utility operations.

2. In instances where it may be desirable to move an Edison employee to an unregulated affiliate, senior management approval of both companies involved in the transfer will be required before the transfer can occur.

3. Edison employees will be free to accept or reject employment with the unregulated affiliates and no involuntary transfers will take place.

4. If an Edison employee elects to accept a position with an unregulated affiliate, he

While Edison did not attempt to evaluate employee compensation based on salary surveys, it did make a comparison of payroll to revenue. This approach provides a quick indicator of overall payroll costs relative to a selected marketplace or industry. Using the 1986 executive compensation survey conducted annually by Sibson & Company, Inc., Edison concluded that for 108 companies the average percentage of payroll to revenues is 12.44% which compares favorably to Edison's 12.07%.

Edison also adjusted PSD's analysis to correct for the improper weighting of jobs and the double counting of companies. PSD's overpayment of APS employees is reduced from 9.2% to 7.5% based on Edison's calculations.

Finally, Edison cites D.86-12-095 for PG&E in which management salary levels exceeded the utility industry average by approximately 8% as recognition that paying a small premium over market benefits the ratepayer as well as the shareholder.

In support of its recommendation, PSD states that its study of employee compensation focused on the market from which Edison draws it labor, categorized payroll data by type of employee, and relied on five independent salary surveys. PSD grouped Edison's work force into five categories: (1) executive, (2) APS, (3) clerical, (4) physical, and (5) technical. PSD found Edison's executive, clerical and physical salaries to be reasonably in accord with market salary levels, and did not recommend an expense reduction for those categories. Since there was insufficient data available for Edison's technical work force, PSD made no ratemaking recommendation for that category. For APS employees, although a benefit comparison was not made, PSD concluded that salary levels are excessive and recommended a 9.2% or $19.7 million reduction in labor expense for this category.

In concluding, PSD states that it is puzzled by Edison's argument that the salary surveys used by PSD are inappropriate for evaluating the reasonableness of compensation to APS employees.

or she will be required to resign from Edison.

5. Edison will provide to the Commission an annual report identifying nonclerical personnel transferred from Edison to the Holding Company or any of the nonutility subsidiaries.

We find the agreement between Edison and PSD as adopted in our decision in A.87-05-007 applicable in resolving these same issues in Edison's general rate case. As a result of the agreement we will increase Edison's other operating revenues by $70,000 for the test year.

Finally, we note that our decision in A.87-05-007 also addresses the royalty to be paid by affiliates on gross revenues. Since that decision provides an in depth analysis of PSD's proposal and concludes that it should not be adopted, we will not repeat that discussion here. Accordingly, we will not adopt PSD's proposed royalty payment on affiliate gross revenues.

K. <u>Hazardous Waste Management</u>

Edison and PSD were the only two parties that addressed this issue. Edison had requested $10.1 million annually for three years for its hazardous waste program and $11.7 in capital expenditures for its underground storage tank program. After reviewing Edison's hazardous waste management proposal PSD introduced Exhibit 65-A which recommended a number of changes in Edison's request. Since Edison has stipulated to PSD's recommendations, we will adopt them with some minor modifications concerning reporting dates and the inclusion of hazardous waste sites other than manufactured gas. The adopted recommendations are detailed
below:

1. Edison should file an application for funding prior to expending funds when its hazardous waste program for the sites it owns is more definite.

PSD wonders why these salary surveys are commissioned if they should not be used to study salaries.

We believe PSD's analysis in this proceeding is a significant improvement over its PG&E proposal. However, before it can be used to judge the reasonableness of Edison's level of payroll expenses, there are further refinements that should be considered. First, comparisons should either be made on a total compensation basis or adjusted to reflect the employees' benefit package. Since employees choose employment opportunities on a total compensation basis, we consider it reasonable to judge utility compensation in the same manner. Second, in addition to point comparisons based on averages information indicating the range of data should be provided. Lastly, Edison's criticisms concerning sample sizes and the duplication of jobs and companies in the survey data should be addressed.

Our objective is to ensure that ratepayers are not burdened with paying for employee compensation levels beyond that which is necessary for Edison to provide safe reliable service at reasonable rates. This type of evaluation is difficult because of the subjectiveness involved in quantifying the variables used. To minimize this, we expect both PSD and Edison in future general rate proceedings to develop an agreed upon data base for judging the reasonableness of employee compensation levels. For this proceeding, we find Edison's justification for its APS compensation levels reasonable.

J. <u>Affiliated Transactions</u>

PSD raised five issues concerning the affiliated relationships of Edison and its subsidiary companies. In this proceeding Edison and PSD have come to agreement on two of these issues: gains on sales of utility assets to affiliates and net income of utility-related subsidiaries. For these issues Edison and PSD recommend that:

2. For hazardous waste sites that Edison does not currently own, it should file an application to receive prospective funding for remedial investigations or work when Edison is ordered by a regulatory agency or a court to perform such work or is notified by a regulatory agency that it is considered a potentially responsible party for these costs.

3. Upon approval Edison should be allowed to place actual program costs into a memorandum account for recovery in a subsequent ECAC or general rate case proceeding. This account should accrue interest at the ECAC interest rate.

4. No retroactive recovery of hazardous waste costs incurred prior to 1988 should be authorized.

5. Edison should file with the Executive Director and the PSD's Resources Branch a comprehensive overview of Edison's hazardous waste management effort, including its underground storage program, by March 31, 1988 and update it annually by January 31 until ordered otherwise.

6. $1 million of Edison's requested budget for mitigating contamination from underground storage tanks should be redirected to the alternate technologies described in Exhibit 65-A.

We will adopt Edison's requested funding level for the underground storage program as agreed to by PSD. Funding for the investigation and clean up of hazardous waste sites will be deferred until Edison files an application(s) as discussed above. A description of the information which Edison should include in its application(s) and annual filings is detailed in Exhibit 65-A.

L. <u>Female/Minority Business Enterprises</u>

Edison implemented its F/MBE program in 1979 to identify F/MBE suppliers and provide them with increased opportunities to participate in Edison's procurement activities. Since that time by

1. All gains on sales of utility assets to nonutility subsidiaries should be recorded above-the-line at market value.

2. Utility-related subsidiaries should be treated, for ratemaking purposes, as utility departments and all transfers of utility assets to those subsidiaries should be at book value.

3. Net income from utility-related subsidiaries should be recorded above-the-line.

Edison and PSD are also in agreement that a $1.0 million increase in Edison's test year estimate of other operating revenues should be adopted to reflect the impact of these recommendations.

PSD's remaining three issues address royalty payments from subsidiaries. For these issues PSD recommends that subsidiaries pay:

1. A royalty or affiliate payment of 5% of gross revenues.

2. A markup royalty of 10% for services provided by the utility.

3. A royalty upon the transfer of an employee from the utility to the subsidiary equal to 50% of the employee's annual salary.

The three issues above were also addressed in A.87-05-007, Edison's request to establish a holding company structure. In A.87-05-007 Edison and PSD submitted a joint exhibit agreeing to: (1) the markup royalty for services provided by the utility and (2) the guidelines for utility employee transfers to affiliates. As stated in the joint exhibit a 5% markup on fully loaded labor costs will be billed to nonutility affiliates for the use of Edison employees. The joint exhibit also sets forth the following guidelines for the transfer of utility employees to affiliates:

D.82-12-101, our generic investigation of utilities' employment practices, and D.84-12-068, Edison's 1985 general rate case, Edison's F/MBE program has been expanded and modified to include reporting requirements. Currently, Edison's reporting requirements include the development of a data collection system to track F/MBE program results by ethnic classifications, annual goal setting, and demonstration of significant progress in the dollar amounts and number of F/MBE contacts awarded.

R.87-02-026, dated February 11, 1987, was initiated in response to PU Sections 8281-8296. This rulemaking proceeding will address long-term goal setting, verification procedures, and annual reporting. Accordingly, Edison's general rate decision will focus only on program funding requirements and past performance in compliance with D.84-12-068.

In addition to Edison's presentation, PSD and American G.I. Forum; Filipino American Political Association (Public Advocates) made recommendations concerning Edison's F/MBE program.

1. Program Funding

Edison requests $636,390 to fund its F/MBE program for test year 1988. As proposed, its budget includes the annual salaries of one F/MBE administrator, one clerk, and eight analysts. This funding level is intended to maintain Edison's F/MBE data base, verify the status of F/MBE firms, and set targets in over 800 procurement categories and nine ethnic/gender classifications. Edison uses the targets to participate in outreach activities and arrive at annual goals for commodities, services, and construction. Although Edison's proposed F/MBE budget does not specifically include funding to comply with PU Sections 8281-8296, Edison believes it is necessary not only to maintain the current program, but to respond to current and future program demands, including requirements associated with PU Sections 8281-8296.

PSD recommends a budget of $505,544. PSD's lower budget level is due to a reduction of $20,000 for certification and the

1. The staffing of the nonregulated affiliates will not be to the detriment of utility operations.

2. In instances where it may be desirable to move an Edison employee to an unregulated affiliate, senior management approval of both companies involved in the transfer will be required before the transfer can occur.

3. Edison employees will be free to accept or reject employment with the unregulated affiliates and no involuntary transfers will take place.

4. If an Edison employee elects to accept a position with an unregulated affiliate, he or she will be required to resign from Edison.

5. Edison will provide to the Commission an annual report identifying nonclerical personnel transferred from Edison to the Holding Company or any of the nonutility subsidiaries.

We find the agreement between Edison and PSD applicable in resolving these same issues in Edison's general rate case. As a result of the agreement we will increase Edison's other operating revenues by $70,000 for the test year.

Finally, we note that A.87-05-007 also addresses the royalty to be paid by affiliates on gross revenues. Accordingly, we will not consider that issue in this decision.

K. <u>Hazardous Waste Management</u>

Edison and PSD were the only two parties that addressed this issue. Edison had requested $10.1 million annually for three years for its hazardous waste program and $11.7 in capital expenditures for its underground storage tank program. After reviewing Edison's hazardous waste management proposal PSD introduced Exhibit 65-A which recommended a number of changes in Edison's request. Since Edison has stipulated to PSD's exclusion of two analysts. Public Advocates has not made a recommendation concerning Edison's program funding level.

2. Performance

D.84-12-068 directed Edison to submit specific information relative to its F/MBE program and demonstrate that it had achieved significant progress in the dollar amounts and number of F/MBE contracts awarded. Exhibit 10 contains Edison's compliance with D.84-12-068. While no party claims that Edison has not complied with D.84-12-068, Public Advocates claims that Edison has made no progress in furthering the development of F/MBE's.

In support of its claim Public Advocates cites Edison's performance over the last three years of less than 4.5% of all contract amounts to F/MBEs and less than 0.3% to blacks. Public Advocates states that Edison has not achieved significant progress in the awarding of contracts to F/MBEs and recommends that:

1. Top executive compensation be tied directly to F/MBE achievement.

2. Substantial long range goals be set.

3. Edison be penalized by requiring that a sum equal to one-half of 1% of its total outside contracts in 1986 ($5 million) be allocated to assisting in direct F/MBE development.

4. Edison be admonished for its poor record.

5. This case be treated separately from R.87-02-026.

6. Edison develop a program to encourage and facilitate joint ventures, develop mechanisms to improve equity and capital sources for minority and women entrepreneurs, and assist F/MBEs in acquiring insurance coverage at favorable rates.

7. A category for Filipino-Americans be included in Edison's F/MBE data collection.

recommendations, we will adopt them with some minor modifications concerning reporting dates and the inclusion of hazardous waste sites other than manufactured gas. The adopted recommendations are detailed below:

1. Edison should file an application for funding prior to expending funds when its hazardous waste program for the sites it owns is more definite. Applications under this procedure are only intended for hazardous waste cleanup at sites included in Edison's general rate case filing and/or in its annual hazardous waste management report.

2. For hazardous waste sites that Edison does not currently own, it should file an application to receive prospective funding for remedial investigations or work when Edison is ordered by a regulatory agency or a court to perform such work or is notified by a regulatory agency that it is considered a potentially responsible party for these costs.

3. Upon approval Edison should be allowed to place actual program costs into a memorandum account for recovery in a subsequent ECAC or general rate case proceeding. This account should accrue interest at the ECAC interest rate.

4. No retroactive recovery of hazardous waste costs incurred prior to 1988 should be authorized.

5. Edison should file with the Executive Director and the PSD's Resources Branch a comprehensive overview of Edison's hazardous waste management effort, including its underground storage program, by March 31, 1988 and update it annually by January 31 until ordered otherwise.

8. Contract awards be reported by service/purchase type.

Additionally, Public Advocates argues that Edison's outreach program has not addressed the inability of F/MBEs to be competitive with white contractors and top management has shown a lack of interest in the F/MBE program.

In spite of Public Advocates' desires to deal with all F/MBE issues in general rate cases we will reaffirm our intentions to address only specific F/MBE program matters in general rate cases. Accordingly, items 1,2,5,7 and 8 will be addressed in R.87-02-026. The remaining items are discussed below.

The record demonstrates that Edison increased its dollar awards to F/MBEs from \$38.3 million in 1984 to \$74.8 million in 1986 and increased the number of awards from 3,805 to 5,025 for the same period. By any measure this was a significant increase for this period. Although these numbers pale in comparison to Edison's total awards, Edison has complied with D.84-12-068 and we will not adopt Public Advocates' recommendations contained in items 3 and 4 above. We will, however, expect Edison to continue to achieve significant increases in the number and amount of awards to F/MBEs.

We agree with Public Advocates that more can be done to assist F/MBEs in successfully competing for Edison contracts. To accomplish this Edison should develop a program which encourages and facilitates joint ventures and provides assistance to F/MBEs in acquiring financing and insurance coverage at rates competitive with Edison's non-F/MBE contractors. We will increase Edison's requested funding to \$700,000 for test year 1988 to implement this expanded F/MBE program and we expect to see the fruit of this enhanced funding in future proceedings.

6. $1 million of Edison's requested budget for mitigating contamination from underground storage tanks should be redirected to the alternate technologies described in Exhibit 65-A.

We will adopt Edison's requested funding level for the underground storage program as agreed to by PSD. Funding for the investigation and clean up of hazardous waste sites will be deferred until Edison files an application(s) as discussed above. A description of the information which Edison should include in its application(s) and annual filings is detailed in Exhibit 65-A.

L. <u>Female/Minority Business Enterprises</u>

Edison implemented its F/MBE program in 1979 to identify F/MBE suppliers and provide them with increased opportunities to participate in Edison's procurement activities. Since that time by D.82-12-101, our generic investigation of utilities' employment practices, and D.84-12-068, Edison's 1985 general rate case, Edison's F/MBE program has been expanded and modified to include reporting requirements. Currently, Edison's reporting requirements include the development of a data collection system to track F/MBE program results by ethnic classifications, annual goal setting, and demonstration of significant progress in the dollar amounts and number of F/MBE contacts awarded.

R.87-02-026, dated February 11, 1987, was initiated in response to PU Sections 8281-8296. This rulemaking proceeding will address long-term goal setting, verification procedures, and annual reporting. Accordingly, Edison's general rate decision will focus only on program funding requirements and past performance in compliance with D.84-12-068.

In addition to Edison's presentation, PSD and American G.I. Forum; Filipino American Political Association (Public Advocates) made recommendations concerning Edison's F/MBE program.

VI. Demand Side Management

A. Introduction

Demand Side Management (DSM) refers to ratepayer funded programs undertaken by the utility to affect customer energy consumption patterns. Over the years our funding of such conservation and load management programs has tracked the availability and price of energy resources. Thus, in the 1970's, when fossil fuels were at a costly premium, we embarked on a course of approving and funding a number of conservation programs. We further stated that it was our intention to make the vigor, imagination, and effectiveness of a utility's conservation efforts a key question in future rate proceedings. (D.84902, 78 CPUC 638 at 746 (1975).)

At that time, we also made clear our reliance on marginal cost principles in assessing the need for conservation programs. Specifically, we observed: "Where the marginal cost of conserved energy is less than the marginal cost of new supply the former should always be the investment of choice." (D.91107, 2 CPUC 2d 596 at 706 (1979).)

More recently, we have reduced our emphasis on large and often costly conservation programs in the face of changing economic and resource conditions impacting the utilities which we regulate. For Edison, these changes, similar to those being experienced by other utilities, have included the following: (1) greater stability in the utility's financial condition, (2) embedded costs above marginal costs due to dramatic decreases in the price of oil and gas, and (3) an excess of available capacity over the next several years due to the completion of large baseload plants and the successful development of qualifying facility resources.

In light of these changes, we have adhered to a policy of "staying the course" with respect to conservation and load management program development and funding. With D.86-12-095 in

1. Program Funding

Edison requests $636,390 to fund its F/MBE program for test year 1988. As proposed, its budget includes the annual salaries of one F/MBE administrator, one clerk, and eight analysts. This funding level is intended to maintain Edison's F/MBE data base, verify the status of F/MBE firms, and set targets in over 800 procurement categories and nine ethnic/gender classifications. Edison uses the targets to participate in outreach activities and arrive at annual goals for commodities, services, and construction. Although Edison's proposed F/MBE budget does not specifically include funding to comply with PU Sections 8281-8296, Edison believes it is necessary not only to maintain the current program, but to respond to current and future program demands, including requirements associated with PU Sections 8281-8296.

PSD recommends a budget of $505,544. PSD's lower budget level is due to a reduction of $20,000 for certification and the exclusion of two analysts. Public Advocates has not made a recommendation concerning Edison's program funding level.

2. Performance

D.84-12-068 directed Edison to submit specific information relative to its F/MBE program and demonstrate that it had achieved significant progress in the dollar amounts and number of F/MBE contracts awarded. Exhibit 10 contains Edison's compliance with D.84-12-068. While no party claims that Edison has not complied with D.84-12-068, Public Advocates claims that Edison has made no progress in furthering the development of F/MBE's.

In support of its claim Public Advocates cites Edison's performance over the last three years of less than 4.5% of all contract amounts to F/MBEs and less than 0.3% to blacks. Public Advocates states that Edison has not achieved significant progress in the awarding of contracts to F/MBEs and recommends that:

PG&E's most recent general rate case, we reduced program funding below previous levels. In taking this action, supported by our lessened concerns regarding supply availability and price, however, we also recognized that future needs required that conservation and load management programs continue in place as a valuable long-term resource. PG&E, PSD, and all other parties were encouraged to continue to evaluate demand-side programs on an equal footing with new supplies. (Id., at p. 94.)

In addition to the influence which a utility's available resources have in determining the level of conservation program funding, the Commission has also recently recognized the need to consider the effects on such programs of competition in the field of electric generation. The competition on which the Commission has focused comes in the form of "bypass," a situation in which the customer chooses to generate its own energy rather than accept the service available from the local public utility.

This phenomenon, of particular concern to the Commission when the self-generation is "uneconomic," has been addressed in a separate section of this decision. However, the Commission's recent decision on this issue in its 3-R's (Risk, Return, and Ratemaking) Rulemaking (R.86-10-001) adopted policies designed to address the problems created by bypass. (D.87-05-071.) Among these policies is one which directly impacts our evaluation of funding for DSM programs.

Specifically, the Commission concluded that the Electric Revenue Adjustment Mechanism (ERAM) should be eliminated for the large light and power class. In D.87-05-071, we found that the risks which ERAM had been intended to neutralize (i.e., instability in interest rates, high rate of inflation, and poor utility financial health) had diminished. Further, we concluded that its elimination for the large power class would create a greater incentive for the utility to maximize revenues from that class and thereby more effectively respond to emerging competition.

1. Top executive compensation be tied directly to F/MBE achievement.

2. Substantial long range goals be set.

3. Edison be penalized by requiring that a sum equal to one-half of 1% of its total outside contracts in 1986 ($5 million) be allocated to assisting in direct F/MBE development.

4. Edison be admonished for its poor record.

5. This case be treated separately from R.87-02-026.

6. Edison develop a program to encourage and facilitate joint ventures, develop mechanisms to improve equity and capital sources for minority and women entrepreneurs, and assist F/MBEs in acquiring insurance coverage at favorable rates.

7. A category for Filipino-Americans be included in Edison's F/MBE data collection.

8. Contract awards be reported by service/purchase type.

Additionally, Public Advocates argues that Edison's outreach program has not addressed the inability of F/MBEs to be competitive with white contractors and top management has shown a lack of interest in the F/MBE program.

In spite of Public Advocates' desires to deal with all F/MBE issues in general rate cases we will reaffirm our intentions to address only specific F/MBE program matters in general rate cases. Accordingly, items 1,2,5,7 and 8 will be addressed in R.87-02-026. The remaining items are discussed below.

The record demonstrates that Edison increased its dollar awards to F/MBEs from $38.3 million in 1984 to $74.8 million in 1986 and increased the number of awards from 3,805 to 5,025 for the same period. By any measure this was a significant increase for

The utilities and interested parties had noted, however, that ERAM had allowed the utilities to pursue conservation, load management and social programs required by the Commission without working directly against the utilities' own interests. Despite this circumstance, we concluded that the most cost-effective conservation programs should still be retained in the large light and power class. We also noted that since our decision on ERAM did not impact the commercial and residential classes, the utilities' incentives to pursue effective conservation for those classes remained unchanged.

D.87-05-071 also included our recognition that many short-term conservation programs might not now be cost-effective due to changing economic and resource conditions. We found, however, that this conclusion was not to be seen as a weakening of our commitment to conservation and load management programs. As stated in D.87-05-071, "[w]e firmly believe long-range conservation is still very important, and utilities should continue to promote reasonable conservation and efficiency options to their customers." (Id., at p. 4.) We noted in particular that when a new factory or new production process is designed, "ignoring energy efficiency would be short-sighted." (Id.) We admonished the utilities, however, to refrain from using ratepayer funds for utility marketing programs aimed at increasing utility profits when ERAM is eliminated.

this period. Although these numbers pale in comparison to Edison's total awards, Edison has complied with D.84-12-068 and we will not adopt Public Advocates' recommendations contained in items 3 and 4 above. However, we are not satisfied with the level of F/MBE participation and expect Edison to achieve substantial and significant increases in the number and amount of awards to each major ethnic group and for women.

We agree with Public Advocates that more can be done to assist F/MBEs in successfully competing for Edison contracts. To accomplish this Edison should develop a program which encourages and facilitates even greater participation of F/MBEs in Edison contracts through joint ventures and through assistance to F/MBEs in meeting financing and insurance coverage at rates competitive with Edison's non-F/MBE contractors. We will increase Edison's requested funding to $700,000 for test year 1988 to implement this expanded F/MBE program and we expect to see the fruit of this enhanced funding in future proceedings.

B. Basic Positions on DSM Funding

In its application, Edison had originally requested for 1988 a funding level of $69.8 million for DSM programs. In March, 1987, this amount was reduced to $60.3 million. In response to Edison's request, the Public Staff Division (PSD) proposed an overall DSM budget of $47 million. As the following table illustrates, funding levels for direct program expenses are the source of the most significant differences between the Edison request and the PSD recommendation.

Edison/PSD 1988 Overall Demand-Side Management Program Expenses Comparison
(Thousands of 1985 Dollars)

Description	Edison	PSD	Variance
Residential Conservation	$17,061	$15,679	$(1,382
Non-Residential Conservation	19,942	14,893	(5,049)
Load Management	12,253	5,456	(6,797)
Marketing	0	0	0
Measurement and Evaluation	6,600	7,325	725
Support Programs	4,784	3,528	(1,256)
Total DSM Programs	60,640	46,881	(13,759)
Adjust. for Program Emphasis	(350)	(350)	(0)
Grand Total DSM Programs	60,290	46,531	(13,759)

In addition to the issue of program funding, Edison and PSD also provided ratemaking and non-budgetary recommendations. These proposals focused on the consolidation of all DSM funds into base rates, the shifting of funds among programs, the handling of budget changes between rate cases, the funding of programs for customer groups removed from ERAM, the changing of reporting requirements, and the use of a consistent set of generic terms for program descriptions and reporting breakdowns.

Several parties offered testimony on both the Edison and PSD proposals. Among them were the California Energy Commission

VI. Demand Side Management

A. Introduction

Demand Side Management (DSM) refers to ratepayer funded programs undertaken by the utility to affect customer energy consumption patterns. Over the years our funding of such conservation and load management programs has tracked the availability and price of energy resources. Thus, in the 1970's, when fossil fuels were at a costly premium, we embarked on a course of approving and funding a number of conservation programs. We further stated that it was our intention to make the vigor, imagination, and effectiveness of a utility's conservation efforts a key question in future rate proceedings. (D.84902, 78 CPUC 638 at 746 (1975).)

At that time, we also made clear our reliance on marginal cost principles in assessing the need for conservation programs. Specifically, we observed: "Where the marginal cost of conserved energy is less than the marginal cost of new supply the former should always be the investment of choice." (D.91107, 2 CPUC 2d 596 at 706 (1979).)

More recently, we have reduced our emphasis on large and often costly conservation programs in the face of changing economic and resource conditions impacting the utilities which we regulate. For Edison, these changes, similar to those being experienced by other utilities, have included the following: (1) greater stability in the utility's financial condition, (2) embedded costs above marginal costs due to dramatic decreases in the price of oil and gas, and (3) an excess of available capacity over the next several years due to the completion of large baseload plants and the successful development of qualifying facility resources.

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(CEC), the California/Nevada Community Action Association (Cal-Neva), and the Thermal Energy Storage Manufacturers' and Contractors' Association (TESMAC). The CEC generally supports the funding levels proposed by Edison in the area of load management, and asserts, along with Edison and TESMAC, that the PSD has provided an overly broad definition of "marketing" in determining which programs may be funded through rates. The CEC also believes that its funding and cost-effectiveness recommendations have been appropriately based on examining Edison's long-term resource needs.

Both the Edison request and the PSD recommendation propose reduced DSM expenditures relative to recent levels. The differences in these proposals relate primarily to different interpretations of recent Commission decisions and utility trends. While Edison has basically made program-specific recommendations, PSD believes that current economic and resource conditions and D.87-05-071 require certain major changes to the entire DSM area.

Among other things, PSD recommends the elimination of DSM funding for virtually all of the large light and power programs and the elimination of ratepayer funding for any utility marketing program or programs with no potential ratepayer benefit. For this purpose, PSD has defined "marketing" programs as those programs which increase the use of at least one fuel (electricity or gas) relative to what would have happened in the absence of the program. PSD states that load retention, which PSD defines as the promotion of the installation of devices which utilize electricity instead of gas, should be considered marketing because resulting increased electric sales would not have existed in the absence of the program.

PSD also recommends that in the event the Commission authorizes any strategic marketing programs in this proceeding, participating customers be required to agree to "give up" or "return" something, e.g., become interruptible customers or

PG&E's most recent general rate case, we reduced program funding below previous levels. In taking this action, supported by our lessened concerns regarding supply availability and price, however, we also recognized that future needs required that conservation and load management programs continue in place as a valuable long-term resource. PG&E, PSD, and all other parties were encouraged to continue to evaluate demand-side programs on an equal footing with new supplies. (Id., at p. 94.)

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otherwise reduce their demands. It is PSD's overall view of marketing which was the source of much debate in this proceeding.

With respect to cost-effectiveness analysis, all parties generally used the tests established by joint CEC/CPUC staff publication known as the "Standard Practice for Cost-Benefit - Analysis of Conservation and Load Management Programs." The tests addressed in that guide include the utility, participant, non-participant, all ratepayer and societal perspectives. Edison did not take issue with certain PSD suggested nomenclature changes to the standard practice nor PSD's redefinition of the nonparticipant test as the rate impact test (RIM). Edison noted, however, that any such changes would be finalized as part of ongoing workshops on standard practice revisions.

While all parties were guided by the same standard, differences existed between Edison and PSD with respect to input assumptions and computation as well as the manner in which the tests were to be applied to the various programs. In evaluating these programs, PSD and the CEC agreed that greatest emphasis should be placed on the all ratepayer test which compares the total device costs to the benefits associated with marginal cost impacts. PSD and the CEC also concurred in using other test results, i.e., the RIM and participant tests, as a means of accounting for the cost-effectiveness implications measured by these tests, particularly equity considerations among customers. Edison stated that it placed priority on the all ratepayer test for informational, educational and survey type programs and the RIM test for programs involving incentives.

Despite the agreement between PSD and the CEC on applicable cost-effectiveness tests, PSD objects to the CEC's criticism that the PSD viewed load management and conservation programs in the short-term. PSD states that it did consider the long-run ramifications of the conservation and load management programs and that it evaluated the cost-effectiveness of these

The utilities and interested parties had noted, however, that ERAM had allowed the utilities to pursue conservation, load management and social programs required by the Commission without working directly against the utilities' own interests. Despite this circumstance, we concluded that the most cost-effective conservation programs should still be retained in the large light and power class. We also noted that since our decision on ERAM did not impact the commercial and residential classes, the utilities' incentives to pursue effective conservation for those classes remained unchanged.

D.87-05-071 also included our recognition that many short-term conservation programs might not now be cost-effective due to changing economic and resource conditions. We found, however, that this conclusion was not to be seen as a weakening of our commitment to conservation and load management programs. As stated in D.87-05-071, "[w]e firmly believe long-range conservation is still very important, and utilities should continue to promote reasonable conservation and efficiency options to their customers." (Id., at p. 4.) We noted in particular that when a new factory or new production process is designed, "ignoring energy efficiency would be short-sighted." (Id.) We admonished the utilities, however, to refrain from using ratepayer funds for utility marketing programs aimed at increasing utility profits when ERAM is eliminated.

programs on the same basis as it would other resource options available to Edison. PSD also expresses its concern regarding the CEC's failure to provide evidence of its own cost-effectiveness analysis in its testimony or in response to a PSD data request.

With respect to this final point raised by PSD, we note that while we greatly appreciate the CEC's participation in this case, it is necessary to address certain procedural flaws in the CEC's presentation in order to ensure the integrity of our rules. The first of these deficiencies relates to the CEC's failure to respond to a PSD data request for the results of its cost-effectiveness evaluation of the Thermal Energy Storage (TES) program. As we have stated in our discussion of marginal costs, parties relying on computer models and related data must provide this information for purposes of cross-examination and rebuttal. This requirement is based not only on statute (Cal.Pub.Util.Code, Section 1821, et al.), but is also dictated by the rules of fairness and due process. The CEC witness acknowledged its failure to provide this information, but indicated on the record during hearings on June 12, 1987, that the information would be provided "early next week." (Tr. at p. 4919.)

The CEC, however, never met this deadline and did not provide the information until after the filing dates for opening and reply briefs in this proceeding. When the information was finally provided to PSD on September 2, 1987, the cover letter revealed that in fact the CEC had relied on PSD's files and output, varying this information only to include a $500/kW installed cost for TES equipment and the PSD's proposed TOU-8 rate schedule. This representation, however, like the CEC's cost-effectiveness study, cannot be considered part of the record in this proceeding having been provided outside the context of the hearing and briefing process.

Another procedural issue related to the CEC's showing must also be noted. Specifically, the CEC was given an extension

B. Basic Positions on DSM Funding

In its application, Edison had originally requested for 1988 a funding level of $69.8 million for DSM programs. In March, 1987, this amount was reduced to $60.3 million. In response to Edison's request, the Public Staff Division (PSD) proposed an overall DSM budget of $47 million. As the following table illustrates, funding levels for direct program expenses are the source of the most significant differences between the Edison request and the PSD recommendation.

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In addition to the issue of program funding, Edison and PSD also provided ratemaking and non-budgetary recommendations. These proposals focused on the consolidation of all DSM funds into base rates, the shifting of funds among programs, the handling of budget changes between rate cases, the funding of programs for customer groups removed from ERAM, the changing of reporting requirements, and the use of a consistent set of generic terms for program descriptions and reporting breakdowns.

Several parties offered testimony on both the Edison and PSD proposals. Among them were the California Energy Commission

of time beyond that offered to other parties to file its reply brief. Ethics and fairness dictate that an extension granted to one, but not all, parties to a proceeding may not be used as an opportunity to respond to briefs which were timely filed. This rule is particularly important in the general rate case setting in which numerous parties are involved and limited time is available. To protect the rights of every party, no party should be granted an advantage over another, and the parties' comments should end with a final, single reply brief.

In its reply brief, however, the CEC did in fact respond at length to the reply brief of PSD. The CEC's brief not only addresses PSD's reply brief in the main discussion, but then examines PSD's reply in a point-by-point analysis contained in an appendix. This approach goes beyond the limits of fairness and prevents our consideration of those portions of the CEC's reply brief directed to the PSD's reply brief.

C. Specific Programs

In this section each of the DSM programs is reviewed with respect to differences in funding requests and non-budgetary recommendations. For each program area, the parties' positions are summarized followed by our resolution of each of the issues presented and our approval of a specific funding level.

1. Residential Conservation

In the Residential Conservation category, Edison and PSD differ by approximately $1.4 million in their funding recommendations. The source of this difference are adjustments recommended by PSD in two areas: (1) Residential Information activities and (2) Energy Management Services. PSD has also proposed non-budgetary restrictions related to the Energy Efficient Home Builders' and the Direct Assistance Programs. The following table summarizes Edison's and PSD's proposals for residential conservation.

(CEC), the California/Nevada Community Action Association (Cal-Neva), and the Thermal Energy Storage Manufacturers' and Contractors' Association (TESMAC). The CEC generally supports the funding levels proposed by Edison in the area of load management, and asserts, along with Edison and TESMAC, that the PSD has provided an overly broad definition of "marketing" in determining which programs may be funded through rates. The CEC also believes that its funding and cost-effectiveness recommendations have been appropriately based on examining Edison's long-term resource needs.

Both the Edison request and the PSD recommendation propose reduced DSM expenditures relative to recent levels. The differences in these proposals relate primarily to different interpretations of recent Commission decisions and utility trends. While Edison has basically made program-specific recommendations, PSD believes that current economic and resource conditions and D.87-05-071 require certain major changes to the entire DSM area.

Among other things, PSD recommends the elimination of DSM funding for the large light and power incentive programs and the elimination of ratepayer funding for any utility marketing program or programs with no potential ratepayer benefit. For this purpose, PSD has defined "marketing" programs as those programs which increase the use of at least one fuel (electricity or gas) relative to what would have happened in the absence of the program. PSD states that load retention, which PSD defines as the promotion of the installation of devices which utilize electricity instead of gas, should be considered marketing because resulting increased electric sales would not have existed in the absence of the program.

PSD also recommends that in the event the Commission authorizes any strategic marketing programs in this proceeding, participating customers be required to agree to "give up" or "return" something, e.g., become interruptible customers or

Residential Conservation
Edison/PSD Expenses Comparison
(Thousands of 1985 Dollars)

Description	Edison	PSD	Variance
Residential Conservation			
Residential Information	$ 2,626	$ 1,919	$(707)
Energy Management Services	4,149	3,474	(675)
Weather & Retrofit Incentives	768	768	0
Energy Eff. Home Builders	1,000	1,000	0
HP Water Heater/Solar Service	40	40	0
Appliance Eff. Incentives	4,105	4,105	0
Direct Assistance	4,373	4,373	0
Total Residential Conservation	17,061	15,679	(1,382)

a. Residential Information

Residential Information includes two programs: (1) the Energy Management Action Line and (2) Give Your Appliances the Afternoon Off. PSD recommends funding for Residential Information at $1,919,000, a $707,200 reduction from Edison's proposed funding level of $2,626,200.

With respect to the Energy Management Action Line, Edison asks that its funding request of $626,200 be approved. PSD, on the other hand, recommends that the budget be constrained to the 1986 recorded level of $454,000. Edison challenges PSD's recommendation on the grounds that, while no increase in calls is anticipated between 1987 and 1988, the calls will represent a significant increase over 1986. Further, Edison argues that despite call volume stability in 1987 and 1988, the calls will be longer and more complex requiring more operator time and training.

PSD responds, however, that it had already taken an expected increase in calls into account in making its recommendation. Additionally, PSD states that it accepted Edison's figures for call increases, even though prior historic experience indicated that a lower estimate was appropriate.

otherwise reduce their demands. It is PSD's overall view of marketing which was the source of much debate in this proceeding.

With respect to cost-effectiveness analysis, all parties generally used the tests established by joint CEC/CPUC staff publication known as the "Standard Practice for Cost-Benefit - Analysis of Conservation and Load Management Programs." The tests addressed in that guide include the utility, participant, non-participant, all ratepayer and societal perspectives. Edison did not take issue with certain PSD suggested nomenclature changes to the standard practice nor PSD's redefinition of the nonparticipant test as the rate impact test (RIM). Edison noted, however, that any such changes would be finalized as part of ongoing workshops on standard practice revisions.

While all parties were guided by the same standard, differences existed between Edison and PSD with respect to input assumptions and computation as well as the manner in which the tests were to be applied to the various programs. In evaluating these programs, PSD and the CEC agreed that greatest emphasis should be placed on the all ratepayer test which compares the total device costs to the benefits associated with marginal cost impacts. PSD and the CEC also concurred in using other test results, i.e., the RIM and participant tests, as a means of accounting for the cost-effectiveness implications measured by these tests, particularly equity considerations among customers. Edison stated that it placed priority on the all ratepayer test for informational, educational and survey type programs and the RIM test for programs involving incentives.

Despite the agreement between PSD and the CEC on applicable cost-effectiveness tests, PSD objects to the CEC's criticism that the PSD viewed load management and conservation programs in the short-term. PSD states that it did consider the long-run ramifications of the conservation and load management programs and that it evaluated the cost-effectiveness of these

The record supports and we find reasonable PSD's recommended funding of $454,000 for Residential Information. PSD properly took into account both historic and anticipated call volume in making its recommendation.

With respect to the Give Your Appliances Off program, Edison believes that its proposed funding level of $2,000,000 is appropriate to reestablish and reinforce the load management message at a time when public awareness and concern for energy issues have diminished. PSD, however, recommends constraining funding for this program to the 1986 recorded level of $1,465,000. PSD notes that although Edison cites increasing media advertising costs as the justification for proposing a 37% funding increase, recorded 1985/1986 expenses and planned 1987 expenses reflect a decrease in funding requirements.

We again find reasonable and adopt PSD's $1,465,000 funding level for the Give Your Appliances Off program. This amount, based on historic and current funding levels, is sufficient to provide the information necessary to communicate the need and the manner in which residential customers can conserve energy.

b. Energy Management Services

In the category of Energy Management Services, PSD proposes a $674,857 or 16% reduction from the $4,148,600 funding level requested by Edison. This reduction is attributable to PSD's proposed funding for the Residential Energy Survey Program. Specifically, PSD recommends the elimination of Class A (on-site) surveys, the institution of a revised mix of survey options, and the limitation on the total number of audits to the 1986 recorded level of 60,000 as opposed to the 28% increase over that level recommended by Edison.

In support of its position, PSD states that costly Class A (in-home) audits are not required by either federal or state law. Should the CEC decide, as the result of current workshops, to require the Class A audit, PSD believes that Edison has sufficient

programs on the same basis as it would other resource options available to Edison. PSD also expresses its concern regarding the CEC's failure to provide evidence of its own cost-effectiveness analysis in its testimony or in response to a PSD data request.

With respect to this final point raised by PSD, we note that while we greatly appreciate the CEC's participation in this case, it is necessary to address certain procedural flaws in the CEC's presentation in order to ensure the integrity of our rules. The first of these deficiencies relates to the CEC's failure to respond to a PSD data request for the results of its cost-effectiveness evaluation of the Thermal Energy Storage (TES) program. As we have stated in our discussion of marginal costs, parties relying on computer models and related data must provide this information for purposes of cross-examination and rebuttal. This requirement is based not only on statute (Cal.Pub.Util.Code, Section 1821, et al.), but is also dictated by the rules of fairness and due process. The CEC witness acknowledged its failure to provide this information, but indicated on the record during hearings on June 12, 1987, that the information would be provided "early next week." (Tr. at p. 4919.)

The CEC, however, never met this deadline and did not provide the information until after the filing dates for opening and reply briefs in this proceeding. When the information was finally provided to PSD on September 2, 1987, the cover letter revealed that in fact the CEC had relied on PSD's files and output, varying this information only to include a $500/kW installed cost for TES equipment and the PSD's proposed TOU-8 rate schedule. This representation, however, like the CEC's cost-effectiveness study, cannot be considered part of the record in this proceeding having been provided outside the context of the hearing and briefing process.

Another procedural issue related to the CEC's showing must also be noted. Specifically, the CEC was given an extension

budget flexibility to accommodate any needed funding. It is also PSD's position that adequate information can be provided to the customer by a "do it yourself" Class B audit. PSD's notes that its recommendations provide Edison the opportunity to provide whatever direct personal assistance is required after that audit is completed. In PSD's opinion, with a well-developed self audit guide, the need for personal assistance should be the exception, not the general rule.

In response, it is Edison's position that it requires the flexibility to respond to customers who request an in-home survey because of the impact on residential customers which would result from the adoption of its proposed increased rates. In Edison's opinion, the Class A on-site survey is the only tool with the technical sophistication to give the customer an in-depth analysis of residential energy usage. Further, Edison notes that while PSD acknowledged that some on-site follow-up to the Class B survey would be necessary, no funding was recommended by PSD to account for this activity.

While we commend PSD for its cost-cutting efforts in the field of conservation, we do not agree that this area is one which should be a target for such restrictions. Not only can we not rule out the possibility that the Class A survey may be required by the CEC in the test year, but we believe that the need for the survey could escalate in the coming years as we move toward a revenue allocation based on Equal Percent of Marginal Cost (EPMC). As our discussion of revenue allocation indicates, the adoption of EPMC has the greatest impact in terms of increased rates on the residential customer. For this customer group, which does not have purchase or generation alternatives to accepting utility service, energy conservation is the only means by which the residential customer can control his utility bill.

As D.87-05-071 makes clear, despite changing needs for conservation programs for the large power class, the residential

of time beyond that offered to other parties to file its reply brief. Ethics and fairness dictate that an extension granted to one, but not all, parties to a proceeding may not be used as an opportunity to respond to briefs which were timely filed. This rule is particularly important in the general rate case setting in which numerous parties are involved and limited time is available. To protect the rights of every party, no party should be granted an advantage over another, and the parties' comments should end with a final, single reply brief.

In its reply brief, however, the CEC did in fact respond at length to the reply brief of PSD. The CEC's brief not only addresses PSD's reply brief in the main discussion, but then examines PSD's reply in a point-by-point analysis contained in an appendix. This approach goes beyond the limits of fairness and prevents our consideration of those portions of the CEC's reply brief directed to the PSD's reply brief.

C. Specific Programs

In this section each of the DSM programs is reviewed with respect to differences in funding requests and non-budgetary recommendations. For each program area, the parties' positions are summarized followed by our resolution of each of the issues presented and our approval of a specific funding level.

1. Residential Conservation

In the Residential Conservation category, Edison and PSD differ by approximately $1.4 million in their funding recommendations. The source of this difference are adjustments recommended by PSD in two areas: (1) Residential Information activities and (2) Energy Management Services. PSD has also proposed non-budgetary restrictions related to the Energy Efficient Home Builders' and the Direct Assistance Programs. The following table summarizes Edison's and PSD's proposals for residential conservation.

and commercial customers still require effective means of altering or restricting their energy consumption. We therefore find that Edison's proposed funding level of $4,149,000 for Energy Management Services, which would maintain the current audit mix and include a reasonable increase in audits under the Residential Survey Program, is reasonable and should be adopted.

c. Weatherization and Retrofit Incentives

Edison accepted PSD's $768,000 budget recommendation for Weatherization and Retrofit Incentives. PSD's proposed limitation on funding for the Residential Energy Management Incentive Program to attic insulation, wall insulation, storm windows, and duct insulation is also appropriate. Further, PSD has properly targeted the non-coastal areas of Edison's service territory as the focus for Edison's promotional efforts for this program. We therefore find reasonable and adopt PSD's recommended funding level and program specifications for Weatherization and Retrofit Incentives.

d. Residential New Construction

Two programs are included in the category of Residential New Construction: the Energy Efficient Home Builders' Program and the Heat Pump Water Heater/Solar Service Agreements. Edison and PSD are in agreement on the funding levels of $1,000,000 for the home builders' program and $39,700 for the heat pump program. We find reasonable and adopt these funding levels.

Edison disagrees, however, with PSD's non-budgetary recommendation that funding be allowed for central electric heat pumps (a part of the Energy Efficient Home Builders' Program) only where natural gas is not available. Edison states that the program is designed to encourage the installation of high efficiency electrical equipment in a residence that has already been designed with electricity as the choice of fuel. Edison believes that it is in the best interests of all parties to encourage maximum energy efficiency regardless of the availability of other types of energy.

Residential Conservation
Edison/PSD Expenses Comparison
(Thousands of 1985 Dollars)

Description	Edison	PSD	Variance
Residential Conservation			
Residential Information	$ 2,626	$ 1,919	$(707)
Energy Management Services	4,149	3,474	(675)
Weather & Retrofit Incentives	768	768	0
Energy Eff. Home Builders	1,000	1,000	0
HP Water Heater/Solar Service	40	40	0
Appliance Eff. Incentives	4,105	4,105	0
Direct Assistance	4,373	4,373	0
Total Residential Conservation	17,061	15,679	(1,382)

a. Residential Information

Residential Information includes two programs: (1) the Energy Management Action Line and (2) Give Your Appliances the Afternoon Off. PSD recommends funding for Residential Information at $1,919,000, a $707,200 reduction from Edison's proposed funding level of $2,626,200.

With respect to the Energy Management Action Line, Edison asks that its funding request of $626,200 be approved. PSD, on the other hand, recommends that the budget be constrained to the 1986 recorded level of $454,000. Edison challenges PSD's recommendation on the grounds that, while no increase in calls is anticipated between 1987 and 1988, the calls will represent a significant increase over 1986. Further, Edison argues that despite call volume stability in 1987 and 1988, the calls will be longer and more complex requiring more operator time and training.

PSD responds, however, that it had already taken an expected increase in calls into account in making its recommendation. Additionally, PSD states that it accepted Edison's figures for call increases, even though prior historic experience indicated that a lower estimate was appropriate.

We concur with Edison and will not place the restriction proposed by PSD with respect to funding for central electric heat pumps. We do adopt, however, PSD's recommendation that funding not be extended to the heat pump water heater as this element of the home builders' program was found not to be cost-effective. We also follow PSD's suggestion to direct Edison to investigate lower incentives for this program. This direction, however, is applicable to all conservation and load management programs as we seek to ensure the application of ratepayer funds to only efficient and cost-effective programs.

e. Appliance Efficiency Incentives

Edison accepted PSD's $4,105,000 budget recommendation for the Appliance Efficiency Incentives Program. Based on PSD's cost-effectiveness analysis, PSD has properly identified those program elements for which funding will apply (i.e., room air conditioners, evaporative coolers, central air conditioning, central heat pumps, and precoolers). PSD's recommendation restricting eligibility for central air conditioning rebates and for central heat pumps to customers with existing systems is also reasonable. We therefore find reasonable and adopt PSD's proposed funding and specifications for this program.

f. Residential Conservation Direct Assistance

Residential Conservation Direct Assistance is a program a part of which (the low income Energy Assistance Program) involves direct grants to low income customers for hardware installations. These installations include weatherization, evaporative coolers, replacement air conditioners, clock thermostats, portable heaters, and whole house fans. In this proceeding, while Edison accepted PSD's budget recommendation of $4,373,000 for the low income program, Cal-Neva, a statewide association of community action agencies, proposed a funding level of $5,470,000.

The record supports and we find reasonable PSD's recommended funding of $454,000 for Residential Information. PSD properly took into account both historic and anticipated call volume in making its recommendation.

With respect to the Give Your Appliances Off program, Edison believes that its proposed funding level of $2,000,000 is appropriate to reestablish and reinforce the load management message at a time when public awareness and concern for energy issues have diminished. PSD, however, recommends constraining funding for this program to the 1986 recorded level of $1,465,000. PSD notes that although Edison cites increasing media advertising costs as the justification for proposing a 37% funding increase, recorded 1985/1986 expenses and planned 1987 expenses reflect a decrease in funding requirements.

We again find reasonable and adopt PSD's $1,465,000 funding level for the Give Your Appliances Off program. This amount, based on historic and current funding levels, is sufficient to provide the information necessary to communicate the need and the manner in which residential customers can conserve energy.

b. Energy Management Services

In the category of Energy Management Services, PSD proposes a $674,857 or 16% reduction from the $4,148,600 funding level requested by Edison. This reduction is attributable to PSD's proposed funding for the Residential Energy Survey Program. Specifically, PSD recommends the elimination of Class A (on-site) surveys, the institution of a revised mix of survey options, and the limitation on the total number of audits to the 1986 recorded level of 60,000 as opposed to the 28% increase over that level recommended by Edison.

In support of its position, PSD states that costly Class A (in-home) audits are not required by either federal or state law. Should the CEC decide, as the result of current workshops, to require the Class A audit, PSD believes that Edison has sufficient

According to PSD, its recommendation was based on the funding of cost-effective elements, excluding the non-cost-effective portable heater from funding, and constraining the cost per measure to the levels adopted in the 1987 Conservation Load Management Adjustment Clause (D.87-05-021). PSD notes that D.87-05-021 resulted in establishing a $5.5 million budget for the low income program for 1987. PSD states, however, that this decision is not dispositive of the issue of funding in this proceeding. Specifically, PSD cites this Commission's statement in D.87-05-021 that the $5.5 million budget was "an equitable course" to take until our review of all of Edison's energy management programs in this proceeding. (D.87-05-021, at p. 24A.) PSD also believes that its proposed funding level for the Energy Assistance Program is properly proportioned to the program's all ratepayers test cost-effectiveness ratio of 2.0 which fell between the 2.10 for Appliance Efficiency Incentives and 1.64 for Weatherization and Retrofit Incentives.

Cal-Neva states that the funding which it has recommended for the Energy Assistance Program is based on the funding level approved for 1987 in D.87-05-021. Cal-Neva disputes PSD's, and Edison's recommendation to cut 20.1% from 1987 funding for test year 1988 and PSD's proposal to limit the cost per measure to 1986 levels. Cal-Neva asserts that this funding reduction was improperly based on the "parity" or proportion of the total of the residential DSM funds spent on low-income programs. According to Cal-Neva, the proper basis for determining the funding level for this program is not the percentage of funds spent on poor people, but rather the level of market saturation and cost-effectiveness.

In this regard, Cal-Neva states that only it presented direct evidence regarding market saturation. Cal-Neva states that its testimony indicates that only 140,000 of approximately 1 million low-income customers of Edison have been served by the

budget flexibility to accommodate any needed funding. It is also PSD's position that adequate information can be provided to the customer by a "do it yourself" Class B audit. PSD's notes that its recommendations provide Edison the opportunity to provide whatever direct personal assistance is required after that audit is completed. In PSD's opinion, with a well-developed self audit guide, the need for personal assistance should be the exception, not the general rule.

In response, it is Edison's position that it requires the flexibility to respond to customers who request an in-home survey because of the impact on residential customers which would result from the adoption of its proposed increased rates. In Edison's opinion, the Class A on-site survey is the only tool with the technical sophistication to give the customer an in-depth analysis of residential energy usage. Further, Edison notes that while PSD acknowledged that some on-site follow-up to the Class B survey would be necessary, no funding was recommended by PSD to account for this activity.

While we commend PSD for its cost-cutting efforts in the field of conservation, we do not agree that this area is one which should be a target for such restrictions. Not only can we not rule out the possibility that the Class A survey may be required by the CEC in the test year, but we believe that the need for the survey could escalate in the coming years as we move toward a revenue allocation based on Equal Percent of Marginal Cost (EPMC). As our discussion of revenue allocation indicates, the adoption of EPMC has the greatest impact in terms of increased rates on the residential customer. For this customer group, which does not have purchase or generation alternatives to accepting utility service, energy conservation is the only means by which the residential customer can control his utility bill.

As D.87-05-071 makes clear, despite changing needs for conservation programs for the large power class, the residential

program, with market saturation not expected until 2016 at Edison's current rate of service.

Cal-Neva believes that the Energy Assistance Program is clearly needed to enable low-income customers to better manage their energy use at a time when the residential class may experience disproportionate bill increases due to the move to an EPMC revenue allocation. Further, Cal-Neva asserts that the cost-effectiveness of the program is beyond question and clearly exceeds that of the TES Program supported by Edison and the CEC.

Cal-Neva also asserts that the elimination of portable heaters from this program should not result in a funding reduction, but in a funding redirection to more cost-effective program elements. This approach, according to Cal-Neva, would permit more poor people to be served by the program. Cal-Neva also asks the Commission not to rely on currently non-existent federal grant money as a reason to cut either aggregate or per measure funding for low-income conservation.

Despite its acceptance of PSD's funding proposal for the Energy Assistance Program, Edison's statements in its opening brief appear to mirror Cal-Neva's concerns regarding the existence of federal funding for this program and in turn PSD's recommendation to constrain 1988 costs per measure to 1986 costs. Edison states that in 1986 it used a grant from the Federal Solar and Energy Conservation Bank to offset the cost of its direct installation program. According to Edison, the actual cost per conservation measure was actually higher than the costs reported to the Commission which reflected only Edison's costs and not the additional contributions made by grant funding. Edison states that

and commercial customers still require effective means of altering or restricting their energy consumption. We therefore find that Edison's proposed funding level of $4,149,000 for Energy Management Services, which would maintain the current audit mix and include a reasonable increase in audits under the Residential Survey Program, is reasonable and should be adopted.

c. <u>Weatherization and Retrofit Incentives</u>

Edison accepted PSD's $768,000 budget recommendation for Weatherization and Retrofit Incentives. PSD's proposed limitation on funding for the Residential Energy Management Incentive Program to attic insulation, wall insulation, storm windows, and duct insulation is also appropriate. Further, PSD has properly targeted the non-coastal areas of Edison's service territory as the focus for Edison's promotional efforts for this program. We therefore find reasonable and adopt PSD's recommended funding level and program specifications for Weatherization and Retrofit Incentives.

d. <u>Residential New Construction</u>

Two programs are included in the category of Residential New Construction: the Energy Efficient Home Builders' Program and the Heat Pump Water Heater/Solar Service Agreements. Edison and PSD are in agreement on the funding levels of $1,000,000 for the home builders' program and $39,700 for the heat pump program. We find reasonable and adopt these funding levels.

Edison disagrees, however, with PSD's non-budgetary recommendation that funding be allowed for central electric heat pumps (a part of the Energy Efficient Home Builders' Program) only where natural gas is not available. Edison states that the program is designed to encourage the installation of high efficiency electrical equipment in a residence that has already been designed with electricity as the choice of fuel. Edison believes that it is in the best interests of all parties to encourage maximum energy efficiency regardless of the availability of other types of energy.

it has exhausted its grant funding and is not assured that additional funding of this type will be available in 1988.[2]

Edison therefore asks the Commission to allow Edison to negotiate individual costs per measure according to actual market value. If these costs are restricted to the 1986 level, Edison is concerned that available funds will be insufficient to provide targeted customers with a free installation.

As our previous statements indicate, we share Cal-Neva's desire to continue providing adequate funding for residential conservation programs which are cost-effective and will aid residential customers in coping with increased rates. We consider the Energy Assistance Program to be an important means to this end for that group of customers who are least able to absorb rate increases--low income residents.

We also concur with Cal-Neva that cost-effectiveness and market saturation are factors which should be accorded significant weight in determining funding levels. That level should therefore not just be determined by apportioning targeted funds between programs aimed at the same customer group on the basis of the cost-effectiveness rankings of those programs. We believe that the evidence in this proceeding supports a funding level for the Energy Assistance Program greater than that proposed by PSD. Specifically, the record reflects the high cost-effectiveness of the program, the lack of market saturation, the need for continued energy conservation by low income groups, the uncertainty of federal grants, and the questionable applicability of the 1986 cost per measure recommended by PSD in the absence of those grants.

2 PSD states in its reply brief that it learned of Edison's concerns regarding the availability of federal funding for the first time in Edison's opening brief.

We concur with Edison and will not place the restriction proposed by PSD with respect to funding for central electric heat pumps. We do adopt, however, PSD's recommendation that funding not be extended to the heat pump water heater as this element of the home builders' program was found not to be cost-effective. We also follow PSD's suggestion to direct Edison to investigate lower incentives for this program. This direction, however, is applicable to all conservation and load management programs as we seek to ensure the application of ratepayer funds to only efficient and cost-effective programs.

e. Appliance Efficiency Incentives

Edison accepted PSD's $4,105,000 budget recommendation for the Appliance Efficiency Incentives Program. Based on PSD's cost-effectiveness analysis, PSD has properly identified those program elements for which funding will apply (i.e., room air conditioners, evaporative coolers, central air conditioning, central heat pumps, and precoolers). PSD's recommendation restricting eligibility for central air conditioning rebates and for central heat pumps to customers with existing systems is also reasonable. We therefore find reasonable and adopt PSD's proposed funding and specifications for this program.

f. Residential Conservation Direct Assistance

Residential Conservation Direct Assistance is a program a part of which (the low income Energy Assistance Program) involves direct grants to low income customers for hardware installations. These installations include weatherization, evaporative coolers, replacement air conditioners, clock thermostats, portable heaters, and whole house fans. In this proceeding, while Edison accepted PSD's budget recommendation of $4,373,000 for the low income program, Cal-Neva, a statewide association of community action agencies, proposed a funding level of $5,470,000.

Based on this record, we find that it is reasonable to continue funding for the Energy Assistance Program at the level adopted in the 1987 Conservation/Load Management Adjustment Clause (CLMAC). For this program, we therefore adopt the funding level proposed by Cal-Neva of $5,470,000.

2. <u>Non-Residential Conservation</u>

The following table presents an itemized listing of the differences between Edison and PSD for non-residential conservation programs. The overall $5,049,000 difference relates primarily to PSD's recommended reduction for the New Construction (Award Building) program, but also includes PSD adjustments in the Non-Residential Information, Energy Management Service (Commercial), and Energy Management Incentives (Administrative) categories. Edison and PSD also disagree on the participation of large power customers in the commercial and industrial incentive programs. In this instance, this issue, however, did not affect funding.

Non-Residential Conservation
Edison/PSD Expenses Comparison
(Thousands of 1985 Dollars)

Description Non-Residential Conservation	Edison	PSD	Variance
Non-Residential Information	$ 1,110	$ 767	$ (343)
Energy Mgmt. Serv. (Commercial)	4,403	4,090	(313)
Energy Mgmt. Serv. (Industrial)	2,731	2,731	0
Energy Mgmt. Serv. (Agricultural)	1,208	1,208	0
Subtotal Non-Res. Services	9,452	8,796	656
EM Incentives (Commercial)-Small		1,912	
EM Incentives (Commercial)-Med.		1,534	
EM Incentives (Commercial)-Large		0	
Subtotal Comm. Incentives	3,446	3,446	0
EM Incentives (Ind.)-Small/Medium		1,227	
EM Incentives (Ind.)-Large		0	
Subtotal Ind. Incentives	1,227	1,227	0
EM Incentives (Admin.)	678	337	(341)
New Construction	5,139	1,087	(4,052)
Total Non-Residential Conservation	19,942	14,893	(5,049)

a. (CIA) Information

Edison's Non-Residential (Commercial/Industrial/Agricultural (CIA)) Information category is comprised of two programs: CIA Energy Management Outreach and the Major Accounts Representatives Program. Edison states that it considered 1986 expenditures to determine the appropriate overall funding level for this category of $1,109,900. Edison notes, however, that the Major Accounts Representative Program was in operation for only six months in 1986 and that expenses for this component were therefore increased to reflect a full year's activity.

PSD states that its recommended funding level of $767,000, $343,000 below Edison's request, still represents a 96%

According to PSD, its recommendation was based on the funding of cost-effective elements, excluding the non-cost-effective portable heater from funding, and constraining the cost per measure to the levels adopted in the 1987 Conservation Load Management Adjustment Clause (D.87-05-021). PSD notes that D.87-05-021 resulted in establishing a $5.5 million budget for the low income program for 1987. PSD states, however, that this decision is not dispositive of the issue of funding in this proceeding. Specifically, PSD cites this Commission's statement in D.87-05-021 that the $5.5 million budget was "an equitable course" to take until our review of all of Edison's energy management programs in this proceeding. (D.87-05-021, at p. 24A.) PSD also believes that its proposed funding level for the Energy Assistance Program is properly proportioned to the program's all ratepayers test cost-effectiveness ratio of 2.0 which fell between the 2.10 for Appliance Efficiency Incentives and 1.64 for Weatherization and Retrofit Incentives.

Cal-Neva states that the funding which it has recommended for the Energy Assistance Program is based on the funding level approved for 1987 in D.87-05-021. Cal-Neva disputes PSD's, and Edison's recommendation to cut 20.1% from 1987 funding for test year 1988 and PSD's proposal to limit the cost per measure to 1986 levels. Cal-Neva asserts that this funding reduction was improperly based on the "parity" or proportion of the total of the residential DSM funds spent on low-income programs. According to Cal-Neva, the proper basis for determining the funding level for this program is not the percentage of funds spent on poor people, but rather the level of market saturation and cost-effectiveness.

In this regard, Cal-Neva states that only it presented direct evidence regarding market saturation. Cal-Neva states that its testimony indicates that only 240,000 of approximately 1 million low-income customers of Edison have been served by the

increase over the 1985 authorized funding level. PSD also asserts that its proposal includes an increase in funding for the Major Accounts Representative element to reflect a full year of activity. However, PSD proposes a reduction in funding for CIA Energy Management Outreach to a level which PSD believes will be completely adequate, in conjunction with Edison's Energy Management Services Program, to cover the costs of providing information to Edison's CIA customers

We concur with PSD and find reasonable its recommended funding level for this category. PSD's proposal represents a substantial increase over the previously authorized level, takes into account a full year of activity under the Major Accounts Representative Program, and provides adequate funding for "outreach."

b. Energy Management Services

Edison proposes a funding total for all Non-Residential Energy Management Services of $8,341,590 as compared to PSD's recommendation of a $8,028,358 budget. The source of the difference in funding proposals relates to PSD's recommended reductions in the Small Commercial Energy Management Services budget. PSD bases its recommended reduction on an assumed cost per survey of $100, an amount based on the recent recorded average cost per survey.

Edison disagrees with PSD's proposal to limit the average cost-per-survey in this category to 1986 recorded levels. Edison states that in 1988 it plans to offer surveys at the same level as prior years, but only to those customers responding to Edison's survey offer. It is Edison's belief that those customers will be more likely to take action to implement the survey recommendations and that PSD's recommended funding will compromise Edison's ability to sufficiently administer this program.

We find that PSD's recommended funding for the Small Commercial Energy Management Services program based on recent

program, with market saturation not expected until 2016 at Edison's current rate of service.

Cal-Neva believes that the Energy Assistance Program is clearly needed to enable low-income customers to better manage their energy use at a time when the residential class may experience disproportionate bill increases due to the move to an EPMC revenue allocation. Further, Cal-Neva asserts that the cost-effectiveness of the program is beyond question and clearly exceeds that of the TES Program supported by Edison and the CEC.

Cal-Neva also asserts that the elimination of portable heaters from this program should not result in a funding reduction, but in a funding redirection to more cost-effective program elements. This approach, according to Cal-Neva, would permit more poor people to be served by the program. Cal-Neva also asks the Commission not to rely on currently non-existent federal grant money as a reason to cut either aggregate or per measure funding for low-income conservation.

Despite its acceptance of PSD's funding proposal for the Energy Assistance Program, Edison's statements in its opening brief appear to mirror Cal-Neva's concerns regarding the existence of federal funding for this program and in turn PSD's recommendation to constrain 1988 costs per measure to 1986 costs. Edison states that in 1986 it used a grant from the Federal Solar and Energy Conservation Bank to offset the cost of its direct installation program. According to Edison, the actual cost per conservation measure was actually higher than the costs reported to the Commission which reflected only Edison's costs and not the additional contributions made by grant funding. Edison states that

it has exhausted its grant funding and is not assured that additional funding of this type will be available in 1988.[2]

Edison therefore asks the Commission to allow Edison to negotiate individual costs per measure according to actual market value. If these costs are restricted to the 1986 level, Edison is concerned that available funds will be insufficient to provide targeted customers with a free installation.

As our previous statements indicate, we share Cal-Neva's desire to continue providing adequate funding for residential conservation programs which are cost-effective and will aid residential customers in coping with increased rates. We consider the Energy Assistance Program to be an important means to this end for that group of customers who are least able to absorb rate increases--low income residents.

We also concur with Cal-Neva that cost-effectiveness and market saturation are factors which should be accorded significant weight in determining funding levels. That level should therefore not just be determined by apportioning targeted funds between programs aimed at the same customer group on the basis of the cost-effectiveness rankings of those programs. We believe that the evidence in this proceeding supports a funding level for the Energy Assistance Program greater than that proposed by PSD. Specifically, the record reflects the high cost-effectiveness of the program, the lack of market saturation, the need for continued energy conservation by low income groups, the uncertainty of federal grants, and the questionable applicability of the 1986 cost per measure recommended by PSD in the absence of those grants.

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2 PSD states in its reply brief that it learned of Edison's concerns regarding the availability of federal funding for the first time in Edison's opening brief.

recorded costs is reasonable and should be adopted. Edison's statements regarding its proposed change in approach to offering the surveys does not appear to be one which will lead to any significant increase over current recorded costs.

c. Energy Management Incentives: (Commercial & Large Industrial)

Initially, Edison accepted PSD's funding recommendation of $1,227,000, for Non-Residential Energy Management Incentives, with incentives allocated between small, medium, and large commercial customers on the basis of load. While Edison still concurs with this funding level, it disagrees with PSD's subsequent decision, based on PSD's interpretation of D.87-05-071, to eliminate funding for the large commercial customers and to reallocate those funds to the small and medium customers.

Edison believes that PSD's exclusion of the large commercial customer (above 500 kw demand range) from this incentive program is based on a misinterpretation of D.87-05-071. Edison states that in D.87-05-071 the Commission indicated its intent to continue cost-effective conservation programs for large light and power customers. Further, Edison asserts that it is premature and unfair to define "large customers" as all TOU-8 customers. Edison notes that workshops are currently being held to implement the policies adopted in D.87-05-071 and that the definition of "large customer" has yet to be resolved.

We concur with Edison. Our intention in D.87-05-071, as we have indicated in our introduction to DSM, was not the complete elimination of all conservation programs for large power customers. Rather, our concern was that with the elimination of ERAM for the large power customer, the utilities would feel constrained to pursue such programs for these customers. To avoid this result, we specifically ordered that the most cost-effective programs be retained for the large power group. There has been no challenge in this proceeding to the cost-effectiveness of this incentive program

Based on this record, we find that it is reasonable to continue funding for the Energy Assistance Program at the level adopted in the 1987 Conservation/Load Management Adjustment Clause (CLMAC). For this program, we therefore adopt the funding level proposed by Cal-Neva of $5,470,000.

2. Non-Residential Conservation

The following table presents an itemized listing of the differences between Edison and PSD for non-residential conservation programs. The overall $5,049,000 difference relates primarily to PSD's recommended reduction for the New Construction (Award Building) program, but also includes PSD adjustments in the Non-Residential Information, Energy Management Service (Commercial), and Energy Management Incentives (Administrative) categories. Edison and PSD also disagree on the participation of large power customers in the commercial and industrial incentive programs. In this instance, this issue, however, did not affect funding.

for the large commercial customer. Further, we have yet to adopt a definition, as Edison has indicated, of the large power customer, an issue properly resolved in the 3-R's Rulemaking. For these reasons, we believe that PSD's original funding recommendation, both as to the funding level and as to the allocation of those funds between small, medium, and large commercial customers, is reasonable and should be adopted.

d. Energy Management Incentives--Administration

For the administration of the Energy Management Incentives Program, Edison and PSD disagree on the appropriate funding level. Edison supports a budget of $0.68 million, while PSD recommends funds of $0.34 million. PSD's recommended adjustment of Edison's request is based on its corresponding adjustment of CIA incentives. PSD testified that the CIA administration level is directly related to the incentive level. PSD states that despite Edison's apparent denial of this correlation, its witness, on cross-examination, acknowledged that comparable percentage changes had occurred in incentives and administrative expenses between 1985 and 1986.

Edison, however, disputes PSD's assertions. According to Edison, although the incentive levels may have decreased over those originally proposed by Edison, its original estimate of costs to conduct program administration is still appropriate since the customer base qualifying for incentives will remain the same. In Edison's view, the costs of providing information and promoting the program are not altered by a decrease in the incentives level, and a change in that level does not result in a proportional change to administrative costs.

Despite Edison's stated position to the contrary, the record appears to support PSD's contention that there is a direct correlation between incentive levels and administrative costs. We therefore find reasonable and adopt PSD's proposed expense level of

$338,453 for the administration of the Energy Management Incentives Program.

e. Non-Residential New Construction

The category of Non-Residential New Construction includes programs designed to promote energy efficient buildings and appliances. Edison's and PSD's funding recommendations for this program are widely divergent. Specifically, Edison has requested funding of $5.1 million, while PSD recommends a reduction of this budget to $1.1 million.

PSD states that it developed its recommendation by conducting an historical analysis of the costs associated with this and other related programs and by determining the cost-effectiveness of the various elements. PSD states that for the Daylighting portion of this program PSD did not rely on the building standard requirements, but on the historical spending for the Daylighting element alone ($888,000 in 1986). For all other elements in this program area, PSD adopted a figure of $925,000 or 25% of Edison's proposed $3,700,000 for Other New Energy Management Measures. PSD notes that the significant element of the "Other" category is Space Conditioning which is marginally cost-effective.

PSD's recommendation also includes restricting the program to non-TOU-8 customers on the basis of PSD's interpretation of D.87-05-071. The result was to reduce the $1,813,000 originally resulting from PSD's analysis by 40% to PSD's proposed $1.1 million. PSD further recommends that eligibility for incentives for heat pumps be restricted to facilities located in areas where natural gas is unavailable. PSD acknowledges that while this restriction is not included in its testimony it is consistent with PSD's recommendations for Residential New Construction (Energy Efficient Home Builder) and Residential Appliance Efficiency Incentives.

Edison states that its proposal is needed to fund not only the Daylighting program included by PSD, but also Edison's

Non-Residential Conservation
Edison/PSD Expenses Comparison
(Thousands of 1985 Dollars)

Description Non-Residential Conservation	Edison	PSD	Variance
Non-Residential Information	$ 1,110	$ 767	$ (343)
Energy Mgmt. Serv. (Commercial)	4,403	4,090	(313)
Energy Mgmt. Serv. (Industrial)	2,731	2,731	0
Energy Mgmt. Serv. (Agricultural)	1,208	1,208	0
Subtotal Non-Res. Services	9,452	8,796	656
EM Incentives (Commercial)-Small		1,912	
EM Incentives (Commercial)-Med.		1,534	
EM Incentives (Commercial)-Large		0	
Subtotal Comm. Incentives	3,446	3,446	0
EM Incentives (Ind.)-Small/Medium		1,227	
EM Incentives (Ind.)-Large		0	
Subtotal Ind. Incentives	1,227	1,227	0
EM Incentives (Admin.)	678	337	(341)
New Construction	5,139	1,087	(4,052)
Total Non-Residential Conservation	19,942	14,893	(5,049)

a. (CIA) Information

Edison's Non-Residential (Commercial/Industrial/Agricultural (CIA)) Information category is comprised of two programs: CIA Energy Management Outreach and the Major Accounts Representatives Program. Edison states that it considered 1986 expenditures to determine the appropriate overall funding level for this category of $1,109,900. Edison notes, however, that the Major Accounts Representative Program was in operation for only six months in 1986 and that expenses for this component were therefore increased to reflect a full year's activity.

PSD states that its recommended funding level of $767,000, $343,000 below Edison's request, still represents a 96%

proposed Award Building Program in which the Daylighting program has been included. Edison states that the Award Building Program will encourage other energy management measures that increase the overall efficiency of new commercial/industrial buildings above state building standards.

Edison believes that PSD's recommendation is improperly based on historic spending for the Daylighting program, which would therefore exclude recognition of the Award Building Program, and on old building standards. Edison is also concerned that the funding reduction recommended by PSD will not fund the program at a level sufficient to influence commercial and industrial customers to "build-in" energy management technologies during the new construction process.

Edison further asserts that PSD has misinterpreted D.87-05-071 by limiting the program to non-TOU-8 customers and reducing the funding level by $725,200. Edison believes that it is incorrect to exclude TOU-8 customers from participation in this program which has been shown to be cost-effective.

In its reply brief, Edison strongly opposed PSD's introduction in its opening brief of its recommendation to exclude heat pumps from eligibility in the incentive program. Edison states that PSD improperly assumed that the construction practices and use of heat pumps are the same in the residential and non-residential sectors.

We note the legitimacy of many of the arguments which Edison has raised with respect to PSD's proposal. While PSD's approach may be consistent with historic spending and may take into consideration some funding for new programs, we are nevertheless concerned that adopting PSD's proposal may prevent Edison from achieving the legitimate and cost-effective goals of this program.

We also do not concur, as we have stated previously, with PSD's conclusion that D.87-05-071 requires the exclusion of TOU-8 customers from participation in DSM programs. The availability of

increase over the 1985 authorized funding level. PSD also asserts that its proposal includes an increase in funding for the Major Accounts Representative element to reflect a full year of activity. However, PSD proposes a reduction in funding for CIA Energy Management Outreach to a level which PSD believes will be completely adequate, in conjunction with Edison's Energy Management Services Program, to cover the costs of providing information to Edison's CIA customers

We concur with PSD and find reasonable its recommended funding level for this category. PSD's proposal represents a substantial increase over the previously authorized level, takes into account a full year of activity under the Major Accounts Representative Program, and provides adequate funding for "outreach."

b. Energy Management Services

Edison proposes a funding total for all Non-Residential Energy Management Services of $8,341,590 as compared to PSD's recommendation of a $8,028,358 budget. The source of the difference in funding proposals relates to PSD's recommended reductions in the Small Commercial Energy Management Services budget. PSD bases its recommended reduction on an assumed cost per survey of $100, an amount based on the recent recorded average cost per survey.

Edison disagrees with PSD's proposal to limit the average cost-per-survey in this category to 1986 recorded levels. Edison states that in 1988 it plans to offer surveys at the same level as prior years, but only to those customers responding to Edison's survey offer. It is Edison's belief that those customers will be more likely to take action to implement the survey recommendations and that PSD's recommended funding will compromise Edison's ability to sufficiently administer this program.

We find that PSD's recommended funding for the Small Commercial Energy Management Services program based on recent

conservation programs to large power customers again depends on the cost-effectiveness and the need for the program with respect to that customer class. We believe that this program is one to which large power customers are entitled to participate.

We note that PSD's funding level inclusive of TOU-8 customers was $1,813,000. To ensure the sufficient funding for the Award Building Program, we believe that it is reasonable to increase that funding level to $2,500,000, approximately half of Edison's original request. We therefore adopt a budget of $2,500,000 for the Non-Residential New Construction Program. Consistent with our finding in the area of Residential New Construction, we also reject PSD's proposal to limit incentives for heat pumps to facilities located in areas in which natural gas is unavailable.

3. Load Management

Edison's funding request for load management exceeds that recommended by PSD by approximately $6.8 million. This difference is attributable to PSD's proposed reductions in funding of $5.2 million in the Thermal Storage program and $1.6 million in the Water Storage program. The following table illustrates the differences in recommendations between Edison and PSD in this area.

Load Management
Edison/PSD Expenses Comparison
(Thousands of 1985 Dollars)

Description Load Management	Edison	PSD	Variance
AC Cycling - Residential	$ 1,846	$1,846	$ 0
Pool Timer	209	209	0
DSS III	1,718	1,718	0
AC Cycling - Non-Residential	109	109	0
Ther. Storage/Off-Peak Cool	6,515	1,359	(5,156)
Interrupt./Curtailable	215	215	0
Water Storage	1,641	0	(1,641)
Total Load Management	12,253	5,456	(6,797)

recorded costs is reasonable and should be adopted. Edison's statements regarding its proposed change in approach to offering the surveys does not appear to be one which will lead to any significant increase over current recorded costs.

c. **Energy Management Incentives: (Commercial & Large Industrial)**

Initially, Edison accepted PSD's funding recommendation of $1,227,000, for Non-Residential Energy Management Incentives, with incentives allocated between small, medium, and large power customers on the basis of load. While Edison still concurs with this funding level, it disagrees with PSD's subsequent decision, based on PSD's interpretation of D.87-05-071, to eliminate funding for the large commercial customers and to reallocate those funds to the small and medium customers.

Edison believes that PSD's exclusion of the large commercial customer (above 500 kw demand range) from this incentive program is based on a misinterpretation of D.87-05-071. Edison states that in D.87-05-071 the Commission indicated its intent to continue cost-effective conservation programs for large light and power customers. Further, Edison asserts that it is premature and unfair to define "large customers" as all TOU-8 customers. Edison notes that workshops are currently being held to implement the policies adopted in D.87-05-071 and that the definition of "large customer" has yet to be resolved.

We concur with Edison. Our intention in D.87-05-071, as we have indicated in our introduction to DSM, was not the complete elimination of all conservation programs for large power customers. Rather, our concern was that with the elimination of ERAM for the large power customer, the utilities would feel constrained to pursue such programs for these customers. To avoid this result, we specifically ordered that the most cost-effective programs be retained for the large power group. There has been no challenge in this proceeding to the cost-effectiveness of this incentive program

a. Thermal Energy Storage

The most significant controversy in this proceeding related to DSM centered on funding for Edison's TES program. Testimony was presented by Edison, PSD, CEC, and TESMAC. The CEC and TESMAC support Edison's proposed budget of $6,515,000 for the TES program. PSD recommends total TES funding of $1,359,000, a figure equivalent to 40% (the percentage of non-TOU-8 customer participants) of Edison's 1986 expenditures of $3.4 million. The positions of each of the parties are summarized below followed by our resolution of the issues presented.

(1) Edison

Edison states that its TES program, as currently operated, is a cost-effective energy management program with long-term impacts and one for which Edison has received local and national recognition for its effectiveness and success. Edison further asserts that the program is one which the Commission, under the guidelines established in D.87-05-071, intends the utility to continue to promote.[3] In Edison's opinion, PSD's funding recommendation is inadequate to operate an effective program in 1988 and would devastate the industry.

According to Edison, the benefits of the TES program include the mitigation of uneconomic bypass and the improvement of Edison's minimum load problem. It is Edison's experience that TES offers customers a competitive alternative to self-generation by allowing customers to shift a portion of their cooling load to take

3 Edison cites those portions of D.87-05-071 in which the Commission indicated that utilities should continue to promote reasonable and cost-effective conservation and efficiency options for their large power customers. (D.87-05-071, pp. 4, 9.)

for the large commercial customer. Further, we have yet to adopt a definition, as Edison has indicated, of the large power customer, an issue properly resolved in the 3-R's Rulemaking. For these reasons, we believe that PSD's original funding recommendation, both as to the funding level and as to the allocation of those funds between small, medium, and large commercial customers, is reasonable and should be adopted.

d. Energy Management Incentives--Administration

For the administration of the Energy Management Incentives Program, Edison and PSD disagree on the appropriate funding level. Edison supports a budget of $0.68 million, while PSD recommends funds of $0.34 million. PSD's recommended adjustment of Edison's request is based on its corresponding adjustment of CIA incentives. PSD testified that the CIA administration level is directly related to the incentive level. PSD states that despite Edison's apparent denial of this correlation, its witness, on cross-examination, acknowledged that comparable percentage changes had occurred in incentives and administrative expenses between 1985 and 1986.

Edison, however, disputes PSD's assertions. According to Edison, although the incentive levels may have decreased over those originally proposed by Edison, its original estimate of costs to conduct program administration is still appropriate since the customer base qualifying for incentives will remain the same. In Edison's view, the costs of providing information and promoting the program are not altered by a decrease in the incentives level, and a change in that level does not result in a proportional change to administrative costs.

Despite Edison's stated position to the contrary, the record appears to support PSD's contention that there is a direct correlation between incentive levels and administrative costs. We therefore find reasonable and adopt PSD's proposed expense level of

advantage of off-peak rates.[4] Edison further states that PSD has acknowledged that if TES has load retention benefits, the cost-effectiveness results of both Edison and PSD would be understated.

With respect to load retention, Edison has estimated that with the TES option 36 MW of load will be retained on the Edison system in 1988. Without TES as an option, Edison believes that this load would bypass the Edison system and all remaining ratepayers would be financially impacted. If TES is funded as proposed by Edison, Edison states that the anticipated net benefit to nonparticipating customers would be $32 million (net-present value).

Edison strongly disagrees with PSD's assertion that load retention is synonymous with "marketing," for which ratepayer funding would be inappropriate. It is Edison's position that load retention means "keeping a customer who is already an Edison customer on our system." (Tr. at pp. 4763-4764.) By offering TES as an option, Edison believes that it is providing its customers an additional and appropriate means for the customer to manage its energy use wisely and efficiently.

Edison also disputes PSD's decision to base its funding recommendation on 1986 recorded expenditures. Edison states that program activity has significantly escalated over the last 18 months due to increasing customer interest and awareness, coupled with enthusiastic support from the TES industry.

Finally, on the issue of determining the impact of TES, given its load retention attributes, on gas utility customers,

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4 Edison noted that its current Off-Peak Cooling program installation agreement contains a clause which disqualifies customers' eligibility for any incentive payments on systems using any electricity not purchased from Edison for a period of five years. In Edison's view, this clause mitigates the potential for self-generation bypass to occur as a result of a TES incentive from Edison.

$338,453 for the administration of the Energy Management Incentives Program.

e. Non-Residential New Construction

The category of Non-Residential New Construction includes programs designed to promote energy efficient buildings and appliances. Edison's and PSD's funding recommendations for this program are widely divergent. Specifically, Edison has requested funding of $5.1 million, while PSD recommends a reduction of this budget to $1.1 million.

PSD states that it developed its recommendation by conducting an historical analysis of the costs associated with this and other related programs and by determining the cost-effectiveness of the various elements. PSD states that for the Daylighting portion of this program PSD did not rely on the building standard requirements, but on the historical spending for the Daylighting element alone ($888,000 in 1986). For all other elements in this program area, PSD adopted a figure of $925,000 or 25% of Edison's proposed $3,700,000 for Other New Energy Management Measures. PSD notes that the significant element of the "Other" category is Space Conditioning which is marginally cost-effective.

PSD's recommendation also includes restricting the program to non-TOU-8 customers on the basis of PSD's interpretation of D.87-05-071. The result was to reduce the $1,813,000 originally resulting from PSD's analysis by 40% to PSD's proposed $1.1 million. PSD further recommends that eligibility for incentives for heat pumps be restricted to facilities located in areas where natural gas is unavailable. PSD acknowledges that while this restriction is not included in its testimony it is consistent with PSD's recommendations for Residential New Construction (Energy Efficient Home Builder) and Residential Appliance Efficiency Incentives.

Edison states that its proposal is needed to fund not only the Daylighting program included by PSD, but also Edison's

Edison maintains that the lack of data on gas utility marginal costs precludes the evaluation of a gas utility customer perspective at this time. Edison states that the favorable RIM results, upon which it relied, are independent of and are not affected by the quantification and inclusion of gas side effects of the TES program.

(2) PSD

PSD states that its funding recommendation is based on 1986 recorded expenditures, the exclusion of TOU-8 customers from participation in TES, and the restriction of program funding to the load shifting, as opposed to load retention, attributes of TES. PSD considers the load retention aspect of TES represents marketing for which ratepayer funding is inappropriate.

PSD acknowledges that TES installations have a load shifting effect and that for customer's eligible for TOU rate schedules TES can substantially reduce monthly electrical bills. PSD also recognizes that because the initial cost of the system is relatively high, a utility rebate is a valuable incentive to invest in such a system.

PSD states, however, that even assessed as a load shifting program, the TES program demonstrated marginal cost-effectiveness. PSD states that the cost-effectiveness analyses conducted by Edison, PSD, and the CEC for TES showed an all-ratepayer benefit cost ratio ranging from .94 to 1.3. The RIM tests, while over the threshold for funding, were not, in PSD's view, "very robust." PSD believes that these results demonstrate that any major expansion of this program relative to recent authorized levels is unwarranted.

PSD notes that Edison's testimony reflected that by including the load retention benefits of TES, the program's benefit-cost relationships for the RIM test were improved considerably. In contrast to the .53 RIM benefit cost ratio (BCR) of the load shifting portion of TES participants, PSD states that

proposed Award Building Program in which the Daylighting program has been included. Edison states that the Award Building Program will encourage other energy management measures that increase the overall efficiency of new commercial/industrial buildings above state building standards.

Edison believes that PSD's recommendation is improperly based on historic spending for the Daylighting program, which would therefore exclude recognition of the Award Building Program, and on old building standards. Edison is also concerned that the funding reduction recommended by PSD will not fund the program at a level sufficient to influence commercial and industrial customers to "build-in" energy management technologies during the new construction process.

Edison further asserts that PSD has misinterpreted D.87-05-071 by limiting the program to non-TOU-8 customers and reducing the funding level by $725,200. Edison believes that it is incorrect to exclude TOU-8 customers from participation in this program which has been shown to be cost-effective.

In its reply brief, Edison strongly opposed PSD's introduction in its opening brief of its recommendation to exclude heat pumps from eligibility in the incentive program. Edison states that PSD improperly assumed that the construction practices and use of heat pumps are the same in the residential and non-residential sectors.

We note the legitimacy of many of the arguments which Edison has raised with respect to PSD's proposal. While PSD's approach may be consistent with historic spending and may take into consideration some funding for new programs, we are nevertheless concerned that adopting PSD's proposal may prevent Edison from achieving the legitimate and cost-effective goals of this program.

We also do not concur, as we have stated previously, with PSD's conclusion that D.87-05-071 requires the exclusion of TOU-8 customers from participation in DSM programs. The availability of

the load retention portion of TES showed a favorable RIM BCR of 1.34 and the combined program average (load shifting and load retention) RIM BCR became 1.25.

PSD states, however, that the Edison analysis which purports to capture the load retention benefits of TES omits an accounting for the gas-side costs and lost gas revenues. PSD states that Edison has admitted that gas-side impacts should be, but were not at this time, included in the analysis.

In addition to concerns with the cost-effectiveness of the TES program, PSD also asserts that the load retention aspect of this program represents "marketing" for large power customers for which the Commission in D.87-05-071 has prohibited ratepayer funding. In this proceeding, PSD defines marketing programs as those programs which increase the use of at least one fuel (electricity or gas) relative to what would have happened in the absence of the program. According to PSD, the load retention portion of Edison's TES proposal would clearly have the effect of increasing electricity use compared to what would have happened without the TES incentive.

For the TES program, PSD again asserts its position that D.87-05-071 bars ratepayer-funded DSM programs for the large customer class. In developing its proposed funding level for TES, PSD relied on Edison's estimate that 60% of TES funds were allocated to the TOU-8 group. PSD therefore reduced the 1986 recorded TES expenses by this amount.

In the event the Commission were to authorize any funds for either the load retention portion of TES or the participation of large light and power customers, PSD urges that the overall funding level be divided into several categories. These categories would include Load Shifting TES and Electric Load Retention TES with the further breakdown of each of these categories between Medium/Small and Large Customers. PSD proposes that these categories should also be used for any accounting and

conservation programs to large power customers again depends on the cost-effectiveness and the need for the program with respect to that customer class. We believe that this program is one to which large power customers are entitled to participate.

We note that PSD's funding level inclusive of TOU-8 customers was $1,813,000. To ensure the sufficient funding for the Award Building Program, we believe that it is reasonable to increase that funding level to $2,500,000, approximately half of Edison's original request. We therefore adopt a budget of $2,500,000 for the Non-Residential New Construction Program. Consistent with our finding in the area of Residential New Construction, we also reject PSD's proposal to limit incentives for heat pumps to facilities located in areas in which natural gas is unavailable.

3. <u>Load Management</u>

Edison's funding request for load management exceeds that recommended by PSD by approximately $6.8 million. This difference is attributable to PSD's proposed reductions in funding of $5.2 million in the Thermal Storage program and $1.6 million in the Water Storage program. The following table illustrates the differences in recommendations between Edison and PSD in this area.

Load Management
Edison/PSD Expenses Comparison
(Thousands of 1985 Dollars)

Description Load Management	Edison	PSD	Variance
AC Cycling - Residential	$ 1,846	$1,846	$ 0
Pool Timer	209	209	0
DSS III	1,718	1,718	0
AC Cycling - Non-Residential	109	109	0
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Interrupt./Curtailable	215	215	0
Water Storage	1,641	0	(1,641)
Total Load Management	12,253	5,456	(6,797)

reporting requirements. PSD further recommends that customers receiving TES incentives be required to reimburse Edison in the event the customer installs a cogeneration unit in the next five years.

(3) CEC

As stated previously, the CEC supports Edison's funding request for the TES program. The CEC's primary objections to PSD's proposal focus on PSD's definition of the term "marketing."

The CEC believes that PSD has given the term "marketing" a broader definition than the Commission intended in D.87-05-071. It is the CEC's position that "marketing," as used by the Commission in that order, refers to utility programs for which the primary objective or predominant effect is to increase a utility's sales to the exclusion or minimization of conservation efforts. According to the CEC, programs which are designed to make the system more efficient and reduce customer bills should be encouraged even if they may incidentally increase a utility's sales. Those programs which deserve continued funding, in the CEC's opinion, include those designed to shift load, to reduce utility bills, to promote system efficiency, and to defer costly resource additions. The CEC believes that Edison's TES, water storage, and industrial load shaping programs all meet this criteria.

The CEC also agrees with Edison that the TES program is designed both to retain load (i.e., avoid or mitigate uneconomic bypass) and shift load. The CEC states that these dual goals are not aimed at increasing sales and will in fact provide a cheaper and more efficient alternative to the addition by Edison of a new peaking generation resource.

(4) TESMAC

Like the CEC, TESMAC fully supports the funding level proposed by Edison for the TES program. TESMAC believes that

a. Thermal Energy Storage

The most significant controversy in this proceeding related to DSM centered on funding for Edison's TES program. Testimony was presented by Edison, PSD, CEC, and TESMAC. The CEC and TESMAC support Edison's proposed budget of $6,515,000 for the TES program. PSD recommends total TES funding of $1,359,000, a figure equivalent to 40% (the percentage of non-TOU-8 customer participants) of Edison's 1986 expenditures of $3.4 million. The positions of each of the parties are summarized below followed by our resolution of the issues presented.

(1) Edison

Edison states that its TES program, as currently operated, is a cost-effective energy management program with long-term impacts and one for which Edison has received local and national recognition for its effectiveness and success. Edison further asserts that the program is one which the Commission, under the guidelines established in D.87-05-071, intends the utility to continue to promote.[3] In Edison's opinion, PSD's funding recommendation is inadequate to operate an effective program in 1988 and would devastate the industry.

According to Edison, the benefits of the TES program include the mitigation of uneconomic bypass and the improvement of Edison's minimum load problem. It is Edison's experience that TES offers customers a competitive alternative to self-generation by allowing customers to shift a portion of their cooling load to take

3 Edison cites those portions of D.87-05-071 in which the Commission indicated that utilities should continue to promote reasonable and cost-effective conservation and efficiency options for their large power customers. (D.87-05-071, pp. 4, 9.)

TES provides a cost-effective and important long-term resource for California ratepayers.

TESMAC also agrees with Edison and the CEC that PSD has improperly defined cost-effective load retention as a "marketing activity." TESMAC believes that PSD's overly broad definition of marketing is a formula for the promotion of inefficiency and is inconsistent with D.87-05-071 in which the Commission continued its support for cost-effective conservation and load management programs.

TESMAC also challenges PSD's assertion that Edison's analysis of the load retention benefits of TES should be rejected for its failure to consider any "gas-side" impacts. TESMAC states that it is problematic to quantify "gas-side" impacts when gas marginal costs cannot be adequately determined at this time. Further, TESMAC asserts that PSD's failure to perform such an analysis suggests the substantial methodological and even philosophical problems in currently undertaking such an analysis. TESMAC believes that a program which is cost-effective for the non-participant and all ratepayers would also serve gas consumers who represent those same ratepayers.

In TESMAC's view, TES provides a much more cost-effective and efficient alternative to Edison adding a new peaking generation resource to meet future peak demands. The present $200 per kW TES incentive offered by Edison, in TESMAC's opinion, is much less than the $800 to $1200 per kW cost required for a peaking turbine. In addition, by shifting load to the nighttime, off-peak hours, TESMAC believes that TES may aid any "minimum load" problem being experienced by Edison.

(5) Discussion

Over the past year, we have addressed the issue of funding for TES in several decisions and resolutions. In D.86-12-095, in PG&E's most recent general rate case, we concluded that TES was a cost-effective means of shifting peak load and that

advantage of off-peak rates.[4] Edison further states that PSD has acknowledged that if TES has load retention benefits, the cost-effectiveness results of both Edison and PSD would be understated.

With respect to load retention, Edison has estimated that with the TES option 36 MW of load will be retained on the Edison system in 1988. Without TES as an option, Edison believes that this load would bypass the Edison system and all remaining ratepayers would be financially impacted. If TES is funded as proposed by Edison, Edison states that the anticipated net benefit to nonparticipating customers would be $32 million (net-present value).

Edison strongly disagrees with PSD's assertion that load retention is synonymous with "marketing," for which ratepayer funding would be inappropriate. It is Edison's position that load retention means "keeping a customer who is already an Edison customer on our system." (Tr. at pp. 4763-4764.) By offering TES as an option, Edison believes that it is providing its customers an additional and appropriate means for the customer to manage its energy use wisely and efficiently.

Edison also disputes PSD's decision to base its funding recommendation on 1986 recorded expenditures. Edison states that program activity has significantly escalated over the last 18 months due to increasing customer interest and awareness, coupled with enthusiastic support from the TES industry.

Finally, on the issue of determining the impact of TES, given its load retention attributes, on gas utility customers,

4 Edison noted that its current Off-Peak Cooling program installation agreement contains a clause which disqualifies customers' eligibility for any incentive payments on systems using any electricity not purchased from Edison for a period of five years. In Edison's view, this clause mitigates the potential for self-generation bypass to occur as a result of a TES incentive from Edison.

its use was becoming increasingly widespread. In San Diego Gas and Electric Company's (SDG&E) CLMAC proceeding, we determined that the TES program would be funded at $250/kW, but that amounts that could not cost-effectively be used would be returned to ratepayers. We also directed SDG&E to file with the Commission's Evaluation and Compliance (E&C) Division a cost-effectiveness analysis for each funded TES project. (See D.87-08-046.)

The subject of funding for TES has also been recently considered with respect to Edison. In Resolution E-3053, dated September 10, 1987, we were presented with an Edison advice letter requesting the reallocation of $6.4 million of unspent 1985 and 1986 energy management funds. Edison proposed to refund part of the unspent funds and devote the rest to TES and Load Research. PSD protested the advice letter citing the concerns which it has raised in this proceeding. The advice letter was supported, as in this proceeding, by the CEC and Transphase Systems, Inc., a member of TESMAC.

By Resolution E-3053, we concluded that Edison should be authorized to redirect its funds as proposed, but that "the funding limit [for TES] of $200 per kilowatt such as was required for Pacific Gas and Electric Company in Resolution E-3012" would be imposed. (Resolution E-3053, at p. 4.) We also ordered that amounts directed to the TES program which could not be used cost-effectively should be returned to ratepayers. Edison was further directed to undertake the same reporting requirements as had been ordered for SDG&E in D.87-08-046.

In none of these decisions, however, have we determined that any load retention resulting from TES installations is the equivalent of a utility marketing function. Neither do we believe that D.87-05-071, upon which PSD has apparently relied for its definition of marketing, intended this result any more than that decision can be read to exclude TOU-8 customers from participation in any conservation program. With respect to that

Edison maintains that the lack of data on gas utility marginal costs precludes the evaluation of a gas utility customer perspective at this time. Edison states that the favorable RIM results, upon which it relied, are independent of and are not affected by the quantification and inclusion of gas side effects of the TES program.

(2) PSD

PSD states that its funding recommendation is based on 1986 recorded expenditures, the exclusion of TOU-8 customers from participation in TES, and the restriction of program funding to the load shifting, as opposed to load retention, attributes of TES. PSD considers the load retention aspect of TES represents marketing for which ratepayer funding is inappropriate.

PSD acknowledges that TES installations may have a load shifting effect and that for customer's eligible for TOU rate schedules TES could substantially reduce monthly electrical bills. PSD also recognizes that because the initial cost of the system is relatively high, a utility rebate is a valuable incentive to invest in such a system.

PSD states, however, that even assessed as a load shifting program, the TES program demonstrated marginal cost-effectiveness. PSD states that the cost-effectiveness analyses conducted by Edison, PSD, and the CEC for TES showed an all-ratepayer benefit cost ratio ranging from .94 to 1.3. The RIM tests, while over the threshold for funding, were not, in PSD's view, "very robust." PSD believes that these results demonstrate that any major expansion of this program relative to recent authorized levels is unwarranted.

PSD notes that Edison's testimony reflected that by including the load retention benefits of TES, the program's benefit-cost relationships for the RIM test were improved considerably. In contrast to the .53 RIM benefit cost ratio (BCR) of the load shifting portion of TES participants, PSD states that

exclusion, we reject again PSD's assertion and restate our expectation for utilities to retain reasonable and cost-effective conservation and load management programs for large power customers.

Although we believe that a definition of "marketing," which was not included in D.87-05-071, should be developed in the 3-Rs proceeding, we find that certain conclusions about the relation of load retention to marketing can be drawn in this proceeding. To begin with, D.87-05-071 makes clear our continued commitment to reasonable and cost-effective conservation and load management programs even for large power customers and our desire to mitigate uneconomic bypass. The TES program is a DSM program clearly directed to the goal of improving load management for customers installing TES equipment. The fact that the TES program could result in retaining a customer that might, without TES, have chosen to self-generate would also have the desirable impact of preventing bypass. Nowhere in this record is their testimony demonstrating that Edison seeks funding for TES as a specific means of increasing its sales and revenues.

We therefore find that both the load shifting and load retention aspects of TES can be considered in determining the program's cost-effectiveness and that its load retention attributes can be considered in determining the funding for TES. We do not believe that Edison's inability to quantify the gas-side impact of this program is sufficient to discredit the cost-effectiveness ratios achieved by the TES program under Edison's analysis at this time. We do direct Edison, however, to continue to endeavor to quantify this impact.

We therefore find that TES is a cost-effective program which should be extended to small, medium, and large power customers. We are concerned, however, that if the load retention aspect of TES continues to be emphasized to the degree represented by Edison (50% of TES program funding) that it will increasingly

the load retention portion of TES showed a favorable RIM BCR of 1.34 and the combined program average (load shifting and load retention) RIM BCR became 1.25.

PSD states, however, that the Edison analysis which purports to capture the load retention benefits of TES omits an accounting for the gas-side costs and lost gas revenues. PSD states that Edison has admitted that gas-side impacts should be, but were not at this time, included in the analysis.

In addition to concerns with the cost-effectiveness of the TES program, PSD also asserts that the load retention aspect of this program represents "marketing" for large power customers for which the Commission in D.87-05-071 has prohibited ratepayer funding. In this proceeding, PSD defines marketing programs as those programs which increase the use of at least one fuel (electricity or gas) relative to what would have happened in the absence of the program. According to PSD, the load retention portion of Edison's TES proposal would clearly have the effect of increasing electricity use compared to what would have happened without the TES incentive.

For the TES program, PSD again asserts its position that D.87-05-071 bars ratepayer-funded DSM programs for the large customer class. In developing its proposed funding level for TES, PSD relied on Edison's estimate that 60% of TES funds were allocated to the TOU-8 group. PSD therefore reduced the 1986 recorded TES expenses by this amount.

In the event the Commission were to authorize any funds for either the load retention portion of TES or the participation of large light and power customers, PSD urges that the overall funding level be divided into several categories. These categories would include Load Shifting TES and Electric Load Retention TES with the further breakdown of each of these categories between Medium/Small and Large Customers. PSD proposes that these categories should also be used for any accounting and

appear that the program is one designed more to increase load than to manage load. For these reasons, while we find that the TES program is currently cost-effective and both its load shifting and load retention attributes should be funded, the expenditures related to this program should be closely tracked in the coming years. This tracking can take place by continuing the reporting requirements required by Resolution E-3053 and by establishing, for accounting and reporting purposes, the categories of Load Shifting (Medium/Small and Large Customer) and Load Retention (Medium/Small and Large Customer) suggested by PSD.

With respect to funding levels, we will continue to limit funding to $200/kW. For overall program funding, we believe that PSD has provided us with the appropriate direction for this funding level in its testimony. Specifically, PSD has stated that its funding recommendation for the TES program, had it included TOU-8 customers, would have been $3.4 million based on recorded 1986 expenditures. Although Edison has indicated an increase in activity, our previous comments reflect our concern that the emphasis in providing incentives for TES installations not shift to a utility marketing effort. For this reason, we adopt and find reasonable a $4 million budget for TES, a funding level which is consistent with recently recorded expenditures and will allow for reasonable growth in the program.

b. <u>Water Storage</u>

The Water Storage Program is another area in which the funding proposals of Edison and PSD significantly differ. Edison requests, and the CEC supports, a budget of $1,641,000 for the Water Storage Program. PSD, on the other hand, recommends that no funds be authorized for this program.

According to PSD, this program would result in energy consumption for water pumping by large agricultural customers and water districts to be shifted to off-peak periods. Because PSD's

reporting requirements. PSD further recommends that customers receiving TES incentives be required to reimburse Edison in the event the customer installs a cogeneration unit in the next five years.

(3) CEC

As stated previously, the CEC supports Edison's funding request for the TES program. The CEC's primary objections to PSD's proposal focus on PSD's definition of the term "marketing."

The CEC believes that PSD has given the term "marketing" a broader definition than the Commission intended in D.87-05-071. It is the CEC's position that "marketing," as used by the Commission in that order, refers to utility programs for which the primary objective or predominant effect is to increase a utility's sales to the exclusion or minimization of conservation efforts. According to the CEC, programs which are designed to make the system more efficient and reduce customer bills should be encouraged even if they may incidentally increase a utility's sales. Those programs which deserve continued funding, in the CEC's opinion, include those designed to shift load, to reduce utility bills, to promote system efficiency, and to defer costly resource additions. The CEC believes that Edison's TES, water storage, and industrial load shaping programs all meet this criteria.

The CEC also agrees with Edison that the TES program is designed both to retain load (i.e., avoid or mitigate uneconomic bypass) and shift load. The CEC states that these dual goals are not aimed at increasing sales and will in fact provide a cheaper and more efficient alternative to the addition by Edison of a new peaking generation resource.

(4) TESMAC

Like the CEC, TESMAC fully supports the funding level proposed by Edison for the TES program. TESMAC believes that

and Edison's cost-effectiveness results for this program were marginal, the PSD believes that the program should not be funded.

It is Edison's position, to which the CEC has concurred, that this program is designed to enhance Edison's ability to help major agricultural customers to shift load and lower their operating costs. By eliminating funding for this program, Edison states that DSM program incentives will be inequitably distributed among Edison's customer groups. According to Edison, using PSD's proposed funding levels, approximately 56% of all incentives will be distributed to the residential sector, 44% to the commercial/industrial sector, and 0% to the agricultural and water supply customer group.

We concur with Edison that this program should be funded to achieve its legitimate program goals. As we have stated repeatedly in this order, we recognize the need for cost-effective and reasonable conservation and load management programs for large power customers as well as for residential and small commercial customers. Clearly, the agricultural customers should not be left out of this equation especially when their need to control energy costs is as great as any customer class. We therefore adopt and find reasonable Edison's requested funding level of $1,641,000 for the Water Storage Program. Because we had no other record on reasonable funds for this program, however, we ask Edison to undertake whatever reasonable cost-cutting measures are possible to limit any unnecessary and non-cost-effective spending.

4. Residential and Non-residential Marketing

Despite an original funding request for residential and non-residential marketing programs totaling $8.3 million, Edison accepted PSD's recommendation of no funding for these programs. PSD's recommendation, as well as Edison's acceptance of that position, are based on the Commission's determination in D.87-05-071 that ratepayer funds are not to be used for marketing programs. The CEC, however, continues to support the funding of

TES provides a cost-effective and important long-term resource for California ratepayers.

TESMAC also agrees with Edison and the CEC that PSD has improperly defined cost-effective load retention as a "marketing activity." TESMAC believes that PSD's overly broad definition of marketing is a formula for the promotion of inefficiency and is inconsistent with D.87-05-071 in which the Commission continued its support for cost-effective conservation and load management programs.

TESMAC also challenges PSD's assertion that Edison's analysis of the load retention benefits of TES should be rejected for its failure to consider any "gas-side" impacts. TESMAC states that it is problematic to quantify "gas-side" impacts when gas marginal costs cannot be adequately determined at this time. Further, TESMAC asserts that PSD's failure to perform such an analysis suggests the substantial methodological and even philosophical problems in currently undertaking such an analysis. TESMAC believes that a program which is cost-effective for the non-participant and all ratepayers would also serve gas consumers who represent those same ratepayers.

In TESMAC's view, TES provides a much more cost-effective and efficient alternative to Edison adding a new peaking generation resource to meet future peak demands. The present $200 per kW TES incentive offered by Edison, in TESMAC's opinion, is much less than the $800 to $1200 per kW cost required for a peaking turbine. In addition, by shifting load to the nighttime, off-peak hours, TESMAC believes that TES may aid any "minimum load" problem being experienced by Edison.

(5) <u>Discussion</u>

Over the past year, we have addressed the issue of funding for TES in several decisions and resolutions. In D.86-12-095, in PG&E's most recent general rate case, we concluded that TES was a cost-effective means of shifting peak load and that

the Industrial Load Shaping Program which is part of non-residential marketing.

Additionally, Edison also urges the Commission in this proceeding, as it has in comments filed in the 3-Rs Rulemaking to carefully consider the merits of marketing programs in cases where the cost-effectiveness to ratepayers can be demonstrated. Edison also notes its objection to PSD's recommendation that if strategic marketing programs are adopted, customers "give up something" to participate in those programs.

At the present time, we believe that it is appropriate to defer any funding for marketing programs until further analysis of this issue is undertaken in the 3-Rs Rulemaking. As the parties have recognized, D.87-05-071 specifically prohibited ratepayer funding for utility marketing which we find would generally include the type of activities to have been covered in these programs.

5. Measurement, Evaluation, and Reporting Requirements

In this section, we consider both the funding level of the Measurement and Evaluation Program and the reporting requirements for this program and for DSM generally. With respect to funding, Edison and PSD agree on a level of $7,325,000 for the Measurement and Evaluation Program. These funds cover outside consultant costs associated with technical assessments of new technologies, data collection, and analysis in support of sales and demand forecasts. This funding level reflects Edison's agreement with PSD to transfer $750,000 from FERC Account 923 in the A&G budget to this budget and to transfer an additional $20,000 from A&G expenses to the Customer Survey element of the Commercial Floor Space studies.

Edison, however, does not agree with PSD's recommendation that the expenses associated with the Load Metering and Customer Survey program ($705,000) be included as DSM, as opposed to A&G, expenses. Edison states that it has traditionally categorized these expenses as A&G and that it is appropriate to continue to do

its use was becoming increasingly widespread. In San Diego Gas and Electric Company's (SDG&E) CLMAC proceeding, we determined that the TES program would be funded at $250/kW, but that amounts that could not cost-effectively be used would be returned to ratepayers. We also directed SDG&E to file with the Commission's Evaluation and Compliance (E&C) Division a cost-effectiveness analysis for each funded TES project. (See D.87-08-046.)

The subject of funding for TES has also been recently considered with respect to Edison. In Resolution E-3053, dated September 10, 1987, we were presented with an Edison advice letter requesting the reallocation of $6.4 million of unspent 1985 and 1986 energy management funds. Edison proposed to refund part of the unspent funds and devote the rest to TES and Load Research. PSD protested the advice letter citing the concerns which it has raised in this proceeding. The advice letter was supported, as in this proceeding, by the CEC and Transphase Systems, Inc., a member of TESMAC.

By Resolution E-3053, we concluded that Edison should be authorized to redirect its funds as proposed, but that "the funding limit [for TES] of $200 per kilowatt such as was required for Pacific Gas and Electric Company in Resolution E-3012" would be imposed. (Resolution E-3053, at p. 4.) We also ordered that amounts directed to the TES program which could not be used cost-effectively should be returned to ratepayers. Edison was further directed to undertake the same reporting requirements as had been ordered for SDG&E in D.87-08-046.

In none of these decisions, however, have we determined that any load retention resulting from TES installations is the equivalent of a utility marketing function. Neither do we believe that D.87-05-071, upon which PSD has apparently relied for its definition of marketing, intended this result any more than that decision can be read to exclude TOU-8 customers from participation in any conservation program. With respect to that so since the primary purpose of these activities is to support Edison's load research efforts. According to Edison, these load research activities are for the most part undertaken to determine marginal cost allocations and rate design.

In addition to the its recommendation to shift funds for load research activities from A&G to DSM, PSD also proposes that Edison's current Measurement and Evaluation and general DSM reporting requirements be changed consistent with D.86-12-095. In that order, the Commission provided a detail listing of reporting requirements and filings.

We find that the overall funding level for this program to which the parties have agreed is reasonable and that PSD's non-budgetary recommendations also have merit. To ensure the proper designation of ratepayer funds, we find that it is reasonable to include the funding for Edison's load research activities as a DSM expense. Edison admitted that while these activities are not necessarily related to DSM, they are in fact useful in that regard. Research on load appears to be appropriately included in an area in which load management is a focus.

To further provide consistency in the review of every utility's DSM programs, we also agree with PSD that the reports required for Edison's DSM programs should be developed using the same guidelines which we recently adopted for PG&E. Those reporting requirements and guidelines are set forth at pages 111 through 118 of D.86-12-095 and are incorporated by reference in this decision. We will direct Edison to follow those guidelines in meeting its reporting requirements. While Edison has suggested that the restructuring required to meet these new reporting criteria may increase Edison's costs, we find that the overall DSM budget which we have approved in this proceeding should be adequate for Edison to meet any such increased costs.

exclusion, we reject again PSD's assertion and restate our expectation for utilities to retain reasonable and cost-effective conservation and load management programs for large power customers.

Although we believe that a definition of "marketing," which was not included in D.87-05-071, should be developed in the 3-Rs proceeding, we find that certain conclusions about the relation of load retention to marketing can be drawn in this proceeding. To begin with, D.87-05-071 makes clear our continued commitment to reasonable and cost-effective conservation and load management programs even for large power customers and our desire to mitigate uneconomic bypass. The TES program is a DSM program clearly directed to the goal of improving load management for customers installing TES equipment. The fact that the TES program could result in retaining a customer that might, without TES, have chosen to self-generate would also have the desirable impact of preventing bypass. Nowhere in this record is there testimony demonstrating that Edison, while aware of the potential of a TES to increase its sales and revenues, specifically sought funding for this program for this reason.

We therefore find that both the load shifting and load retention aspects of TES can be considered in determining the program's cost-effectiveness and that its load retention attributes can be considered in determining the funding for TES. We do not believe that Edison's inability to quantify the gas-side impact of this program is sufficient to discredit the cost-effectiveness ratios achieved by the TES program under Edison's analysis at this time. We do direct Edison, however, to continue to endeavor to quantify this impact consistent with the recently revised Standard Practice Manual for Economic Evaluation of Demand Side Management Programs.

We therefore find that TES is a cost-effective program which should be extended to small, medium, and large power

6. Support Programs

The following table summarizes the recommendations of Edison and PSD in the support programs category. Reductions in funding have been recommended by PSD for each element of this program (Public Awareness, Advertising, and Management/Administration/Regulatory Support) yielding a total difference between PSD and Edison of $1.3 million.

Support Programs
Edison/PSD Expenses Comparison
(Thousands of 1985 Dollars)

Description Support Programs	Edison	PSD	Variance
Public Awareness	$1,382	$1,031	$ (351)
Advertising	1,000	492	(508)
Mgmt./Admin./Reg. Support	2,402	2,005	(397)
Total Support	4,784	3,528	(1,256)

a. Public Awareness

The $351,000 difference between Edison's request and PSD's recommendation in the Public Awareness area relates primarily to PSD's proposed reduction in the funding requested by Edison for the Save Energy at School program. Edison states that it has requested an increase in funding for this program (67% over 1985 authorized funding) based on two factors. The first, according to Edison, is the expansion of the elementary school program to increase visits from 70 to 250. The second is the development and implementation of a program targeted to the secondary school level. Because PSD did not allow for these changes, Edison believes that PSD's recommended funding level is not sufficient to properly implement the program.

PSD states, however, that while it approves of the Save Energy at School project, it cannot endorse the Edison's proposed 80% increase in funding over recorded 1986 expenses. PSD believes that its recommended 25% increase over 1986 recorded expenditures customers. We are concerned, however, that if the load retention aspect of TES continues to be emphasized to the degree represented by Edison (50% of TES program funding) that it will increasingly appear that the program is one designed more to increase load than to manage load. For these reasons, while we find that the TES program is currently cost-effective and both its load shifting and load retention attributes should be funded, the expenditures related to this program should be closely tracked in the coming years. This tracking can take place by continuing the reporting requirements required by Resolution E-3053 and by establishing, for accounting and reporting purposes, the categories of Load Shifting (Medium/Small and Large Customer) and Load Retention (Medium/Small and Large Customer) suggested by PSD.

With respect to funding levels, we will continue to limit funding to $200/kW. For overall program funding, we believe that PSD has provided us with the appropriate direction for this funding level in its testimony. Specifically, PSD has stated that its funding recommendation for the TES program, had it included TOU-8 customers, would have been $3.4 million based on recorded 1986 expenditures. Although Edison has indicated an increase in activity, our previous comments reflect our concern that the emphasis in providing incentives for TES installations not shift to a utility marketing effort. For this reason, we adopt and find reasonable a $4 million budget for TES, a funding level which is consistent with recently recorded expenditures and will allow for reasonable growth in the program.

b. Water Storage

The Water Storage Program is another area in which the funding proposals of Edison and PSD significantly differ. Edison requests, and the CEC supports, a budget of $1,641,000 for the Water Storage Program. PSD, on the other hand, recommends that no funds be authorized for this program.

will allow Edison to begin penetration into secondary schools without significantly increasing funding requirements. For the remaining programs, PSD recommends constraining the test year 1988 funding level to the 1986 recorded level.

We find that PSD has taken into account the activities required by Edison to implement its Save Energy at School program and has proposed a reasonable increase in funding over recorded 1986 expenditures to adequately cover those activities. We also concur with PSD, in our efforts to reasonably constrain conservation and load management expenditures, to hold the remaining programs to funding levels recorded for 1986. We therefore adopt and find reasonable a funding level of $1,031,000 for the Public Awareness program.

b. Advertising

Edison and PSD also vary on the appropriate funding for advertising. PSD has recommended a reduction of Edison's request of $1,000,000 to $492,000.

It is Edison's position that its funding request is necessary to meet its obligation to educate and remind customers of the benefits of energy management. Edison asserts that this role will become increasingly significant in 1988 with the media's continued lack of emphasis on energy issues in general and energy management in particular.

PSD notes, however, that Edison had also asserted an increased need for advertisement in its test year 1985 general rate case. PSD states that in D.84-12-068 at page 202, the Commission rejected Edison's argument, concluding that "general advertising costs should be kept to a minimum especially since many of Edison's programs provide for their own promotion." PSD believes that this finding is still as "current" as the media trends cited by Edison.

We concur with PSD. The fact of individual program promotion has not changed since Edison's last general rate case. We do not believe that it is warranted for Edison to engage in

According to PSD, this program would result in energy consumption for water pumping by large agricultural customers and water districts to be shifted to off-peak periods. Because PSD's and Edison's cost-effectiveness results for this program were marginal, the PSD believes that the program should not be funded.

It is Edison's position, to which the CEC has concurred, that this program is designed to enhance Edison's ability to help major agricultural customers to shift load and lower their operating costs. By eliminating funding for this program, Edison states that DSM program incentives will be inequitably distributed among Edison's customer groups. According to Edison, using PSD's proposed funding levels, approximately 56% of all incentives will be distributed to the residential sector, 44% to the commercial/industrial sector, and 0% to the agricultural and water supply customer group.

We concur with Edison that this program should be funded to achieve its legitimate program goals. As we have stated repeatedly in this order, we recognize the need for cost-effective and reasonable conservation and load management programs for large power customers as well as for residential and small commercial customers. Clearly, the agricultural customers should not be left out of this equation especially when their need to control energy costs is as great as any customer class. We therefore adopt and find reasonable Edison's requested funding level of $1,641,000 for the Water Storage Program. Because we had no other record on reasonable funds for this program, however, we ask Edison to undertake whatever reasonable cost-cutting measures are possible to limit any unnecessary and non-cost-effective spending.

4. Residential and Non-residential Marketing

Despite an original funding request for residential and non-residential marketing programs totaling $8.3 million, Edison accepted PSD's recommendation of no funding for these programs. PSD's recommendation, as well as Edison's acceptance of that duplicative spending and find that the expenses for general advertising should be minimized. We therefore find reasonable and adopt PSD's proposed budget for Advertising of $492,000.

c. Management/Administration/Regulatory Support

The difference between PSD and Edison for the funding of the Management/Administration/Regulatory Support program is $398,000. PSD states that its recommended funding level of $2,003,760 for this program is based on historical spending patterns which reflect that administrative and management expenses should not exceed 4.5% of total program costs. In developing its recommendation for support program funding, PSD applied this formula to its own total program costs of $44,528,000.

Edison states that its requested funding level of $2,402,000 for this program is necessary to increase the efficient use of electricity through the development, implementation, and coordination of cost-effective energy management programs. Edison states that it does not agree with PSD's method of funding based on a proportional allocation of administrative and management costs to program costs. Reduced program funding, according to Edison, does not proportionally reduce the effort required to manage and maintain accountability for energy management activities.

Our only problem in adopting the funding level recommended by PSD is that it is based on an overall level of funding which differs from our adopted level. We also seek to ensure adequate funding for Edison to administer and manage its DSM programs. We therefore adopt a funding level of $2,200,000 for Management/Administration/Regulatory Support, a level which we find is more closely matched to our adopted level of funding and which will enable Edison to properly implement its DSM programs.

7. Other Demand Side Management Issues

a. Consolidation of DSM Program Funding

Edison proposes two changes relating to the consolidation of all DSM program funding in base rates starting with Test Year position, are based on the Commission's determination in D.87-05-071 that ratepayer funds are not to be used for marketing programs. The CEC, however, continues to support the funding of the Industrial Load Shaping Program which is part of non-residential marketing.

Additionally, Edison also urges the Commission in this proceeding, as it has in comments filed in the 3-Rs Rulemaking, to carefully consider the merits of marketing programs in cases where the cost-effectiveness to ratepayers can be demonstrated. Edison also notes its objection to PSD's recommendation that if strategic marketing programs are adopted, customers "give up something" to participate in those programs.

At the present time, we believe that it is appropriate to defer any funding for marketing programs until further analysis of this issue is undertaken in the 3-Rs Rulemaking. As the parties have recognized, D.87-05-071 specifically prohibited ratepayer funding for utility marketing which we find would generally include the type of activities to have been covered in these programs. Edison should therefore pursue the merits of marketing to all customer classes in the 3-R proceeding.

5. <u>Measurement, Evaluation, and Reporting Requirements</u>

In this section, we consider both the funding level of the Measurement and Evaluation Program and the reporting requirements for this program and for DSM generally. With respect to funding, Edison and PSD agree on a level of $7,325,000 for the Measurement and Evaluation Program. These funds cover outside consultant costs associated with technical assessments of new technologies, data collection, and analysis in support of sales and demand forecasts. This funding level reflects Edison's agreement with PSD to transfer $750,000 from FERC Account 923 in the A&G budget to this budget and to transfer an additional $20,000 from A&G expenses to the Customer Survey element of the Commercial Floor Space studies.

1988. These changes include (1) the elimination of funding of the Residential Conservation Financing Program (RCFP) through the CLMAC balancing account and (2) the elimination of ERAM funding for the Off-Peak Cooling (TES) program. PSD fully concurs with these recommendations which are also consistent with funding changes made in the PG&E general rate case. (D.86-12-095.) We concur with the parties and adopt these changes as reasonable and consistent with D.86-12-095. In implementing this change, Edison's CLMAC billing factor should be reduced in an amount consistent with D.87-05-021 in Edison's most recent CLMAC proceeding.

b. $2.5 Million Limit on Funding Shifts

Edison proposes to eliminate the $2.5 million limit on funding shifts within major program categories (i.e., Residential Conservation, Commercial/Industrial/Agricultural Conservation, and Load Management). Edison states that this limit, established in Edison's last general rate case (D.84-12-068), hampers its ability to respond to changing needs. Edison states that it has a demonstrated track record of implementing programs consistent with Commission policy and considers energy management an important resource alternative. Elimination of the funding limit, in Edison's view, will increase Edison's flexibility to derive the maximum benefit from energy management.

PSD, however, strongly recommends that the cap remain in place and that advice letter filings for funding shifts of $2.5 million or more continue to be required. PSD does recommend, however, that the categories be modified to give Edison more flexibility within program areas.

Specifically, PSD recommends that the current three program categories be replaced with the following six categories: (1) Energy Services and Information Programs (Residential and Non-Residential); (2) Residential and Non-Residential Conservation Incentive Programs; (3) Load Management Programs; (4) Marketing Programs (if any are funded in spite of PSD's recommendations and

Edison, however, does not agree with PSD's recommendation that the expenses associated with the Load Metering and Customer Survey program ($705,000) be included as DSM, as opposed to A&G expenses. Edison states that it has traditionally categorized these expenses as A&G and that it is appropriate to continue to do so since the primary purpose of these activities is to support Edison's load research efforts. According to Edison, these load research activities are for the most part undertaken to determine marginal cost allocations and rate design.

In addition to the its recommendation to shift funds for load research activities from A&G to DSM, PSD also proposes that Edison's current Measurement and Evaluation and general DSM reporting requirements be changed consistent with D.86-12-095. In that order, the Commission provided a detail listing of reporting requirements and filings.

We find that the overall funding level for this program to which the parties have agreed is reasonable and that PSD's non-budgetary recommendations also have merit. To ensure the proper designation of ratepayer funds, we find that it is reasonable to include the funding for Edison's load research activities as a DSM expense. Edison admitted that while these activities are not necessarily related to DSM, they are in fact useful in that regard. Research on load appears to be appropriately included in an area in which load management is a focus.

To further provide consistency in the review of every utility's DSM programs, we also agree with PSD that the reports required for Edison's DSM programs should be developed using the same guidelines which we recently adopted for PG&E. Those reporting requirements and guidelines are set forth at pages 111 through 118 of D.86-12-095 and are incorporated by reference in this decision. We will direct Edison to follow those guidelines in meeting its reporting requirements and to use the generic DSM definitions being established in the Reporting Requirements Manual

Edison's withdrawal of those labeled as such); (5) Measurement and Evaluation; and (6) Energy Management Support. PSD further proposes that any funding shift over $2.5 million within categories or any funding shift between the categories should be requested by an advice letter filing. PSD notes that its proposal will provide Edison with more flexibility in managing its conservation and load management program budgets since Edison will not need to submit an advice letter to shift the dollars covered by the cap.

PSD refutes Edison's assertion that PSD did not provide any evidence to support its recommended continuation of the cap on funding shifts. PSD states that the development of its new program categories was based on an independent cost-effectiveness analysis and programmatic review.

We note that the $2.5 million limit on funding shifts at issue in this proceeding has been maintained since Edison's 1983 test year general rate case. (See, D.82-12-055, D.84-12-068.) Specifically, we had intended by our prior orders to grant Edison the discretion to reallocate up to $2.5 million within its three basic conservation program categories. Advice letter filings were required, however, for shifts among the three major program categories or for shifts of greater than $2.5 million within the program category.

Edison now suggests that instead of improving its management flexibility, this funding limit has hampered its ability to respond to Commission conservation directives. We are slightly perplexed by this assertion, unless Edison's proposed elimination of the $2.5 million cap includes the elimination of advice letters for inter-category and intra-category funding shifts. This position is untenable especially with our increased need to control conservation and load management spending.

To enhance Edison's flexibility in managing its DSM program funding, we are at most willing to continue to maintain the $2.5 million allowance on funding shifts within the three major drafted in response to D.86-12-095. While Edison has suggested that the restructuring required to meet these new reporting criteria may increase Edison's costs, we find that the overall DSM budget which we have approved in this proceeding should be adequate for Edison to meet any such increased costs.

6. Support Programs

The following table summarizes the recommendations of Edison and PSD in the support programs category. Reductions in funding have been recommended by PSD for each element of this program (Public Awareness, Advertising, and Management/Administration/Regulatory Support) yielding a total difference between PSD and Edison of $1.3 million.

Support Programs
Edison/PSD Expenses Comparison
(Thousands of 1985 Dollars)

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Total Support	4,784	3,528	(1,256)

a. Public Awareness

The $351,000 difference between Edison's request and PSD's recommendation in the Public Awareness area relates primarily to PSD's proposed reduction in the funding requested by Edison for the Save Energy at School program. Edison states that it has requested an increase in funding for this program (67% over 1985 authorized funding) based on two factors. The first, according to Edison, is the expansion of the elementary school program to increase visits from 70 to 250. The second is the development and implementation of a program targeted to the secondary school level. Because PSD did not allow for these changes, Edison believes that program categories and to reject PSD's suggestion for increasing the number of categories. PSD's suggestion would not seem to improve Edison's flexibility since advice letters would be required for every shift between categories, and the increase in categories would obviously result in an increase in the instances when advice letters would be required. We continue our admonition to Edison stated in D.84-12-068, however, that our E&C Division should be advised of all changes in program emphasis whether or not an advice letter is required. We therefore find reasonable and adopt the continuation of the three basic DSM program categories of Residential Conservation, Commercial/Industrial/Agricultural Conservation, and Load Management, and of advice letter filings for funding shifts between these three major program categories or for shifts of greater than $2.5 million within those categories.

c. <u>Energy Management Salary Budget</u>

As required by Ordering Paragraph 12 of D.84-12-068 in Edison's last general rate case, Edison has reduced the Corporate Energy Management labor budget by over 20% and provided a numerical count by job category and salary range and a description of each job category. Based on these actions, we find that Edison has complied with D.84-12-068.

d. <u>PSD Program Definitions</u>

PSD recommends that for future reporting requirements and applications Edison be directed to use the program definitions established and used by the PSD in this proceeding. According to PSD, its definitions use generic names rather than Edison promotional names (e.g., non-residential new construction rather than Award Building Program), distinguish between participating customer classes, and reflect the program purpose. PSD believes that this approach is essential to tracking similar programs with different names over time and to providing meaningful cost-effectiveness analyses.

PSD's recommended funding level is not sufficient to properly implement the program.

PSD states, however, that while it approves of the Save Energy at School project, it cannot endorse the Edison's proposed 80% increase in funding over recorded 1986 expenses. PSD believes that its recommended 25% increase over 1986 recorded expenditures will allow Edison to begin penetration into secondary schools without significantly increasing funding requirements. For the remaining programs, PSD recommends constraining the test year 1988 funding level to the 1986 recorded level.

We find that PSD has taken into account the activities required by Edison to implement its Save Energy at School program and has proposed a reasonable increase in funding over recorded 1986 expenditures to adequately cover those activities. We also concur with PSD, in our efforts to reasonably constrain conservation and load management expenditures, to hold the remaining programs to funding levels recorded for 1986. We therefore adopt and find reasonable a funding level of $1,031,000 for the Public Awareness program.

b. Advertising

Edison and PSD also vary on the appropriate funding for advertising. PSD has recommended a reduction of Edison's request of $1,000,000 to $492,000.

It is Edison's position that its funding request is necessary to meet its obligation to educate and remind customers of the benefits of energy management. Edison asserts that this role will become increasingly significant in 1988 with the media's continued lack of emphasis on energy issues in general and energy management in particular.

PSD notes, however, that Edison had also asserted an increased need for advertisement in its test year 1985 general rate case. PSD states that in D.84-12-068 at page 202, the Commission rejected Edison's argument, concluding that "general advertising

We find PSD's suggestion to be meritorious. We believe that as our scrutiny of conservation programs and their cost-effectiveness has intensified so has our need to track these programs and ensure that duplicative spending does not result. In the rate case setting, such consistency is even more critical as multiple programs are reviewed and funding levels are approved. We therefore adopt PSD's definitions and direct Edison to use these definitions in all future rate, offset, and advice letter proceedings.

D. Adopted Results

The following table summarizes our adopted funding levels for Edison's DSM programs:

costs should be kept to a minimum especially since many of Edison's programs provide for their own promotion." PSD believes that this finding is still as "current" as the media trends cited by Edison.

We concur with PSD. The fact of individual program promotion has not changed since Edison's last general rate case. We do not believe that it is warranted for Edison to engage in duplicative spending and find that the expenses for general advertising should be minimized. We therefore find reasonable and adopt PSD's proposed budget for Advertising of $492,000.

c. Management/Administration/Regulatory Support

The difference between PSD and Edison for the funding of the Management/Administration/Regulatory Support program is $398,000. PSD states that its recommended funding level of $2,003,760 for this program is based on historical spending patterns which reflect that administrative and management expenses should not exceed 4.5% of total program costs. In developing its recommendation for support program funding, PSD applied this formula to its own total program costs of $44,528,000.

Edison states that its requested funding level of $2,402,000 for this program is necessary to increase the efficient use of electricity through the development, implementation, and coordination of cost-effective energy management programs. Edison states that it does not agree with PSD's method of funding based on a proportional allocation of administrative and management costs to program costs. Reduced program funding, according to Edison, does not proportionally reduce the effort required to manage and maintain accountability for energy management activities.

Our only problem in adopting the funding level recommended by PSD is that it is based on an overall level of funding which differs from our adopted level. We also seek to ensure adequate funding for Edison to administer and manage its DSM programs. We therefore adopt a funding level of $2,200,000 for Management/Administration/Regulatory Support, a level which we find

Adopted 1988 Demand Side Management Program Expenses

Residential Conservation	
Residential Information	$ 1,919
Energy Management Services	4,149
Weather & Retrofit Incentives	768
Energy Eff. Home Builders	1,000
HP Water Heater/Solar Service	40
Appliance Eff. Incentives	4,105
Direct Assistance	5,470
	17,451
Non-Residential Conservation	
Non-Residential Information	767
Energy Management Services	8,029
Energy Management Incentives (Comm.)	3,446
Energy Management Incentives (Ind.)	1,227
Energy Management Incentives (Admin.)	338
New Construction	2,500
	16,307
Load Management	
AC Cycling - Residential	1,846
Pool Timer	209
DSS III	1,718
AC Cycling - Non-Residential	109
Therm. Storage/Off-Peak Cool	4,000
Interrupt./Curtailable	215
Water Storage	1,641
	9,738
Measurement & Evaluation	7,325
Support Programs	
Public Awareness	1,031
Advertising	492
Mgmt./Admin./Reg. Support	2,200
	3,723
Grand Total DSM Programs	54,544
Adjustments for Program Impacts	(350)
Grand Total DSM Programs	54,194

is more closely matched to our adopted level of funding and which will enable Edison to properly implement its DSM programs.

7. Other Demand Side Management Issues

a. Consolidation of DSM Program Funding

Edison proposes two changes relating to the consolidation of all DSM program funding in base rates starting with Test Year 1988. These changes include (1) the elimination of funding of the Residential Conservation Financing Program (RCFP) through the CLMAC balancing account and (2) the elimination of ERAM funding for the Off-Peak Cooling (TES) program. PSD fully concurs with these recommendations which are also consistent with funding changes made in the PG&E general rate case. (D.86-12-095.)

We concur with the parties and generally adopt these changes as reasonable and consistent with D.86-12-095. To provide an orderly transition to base rate recovery of TES incentive payments, however, all TES incentive payment related to contracts executed prior to January 1, 1988 should continue to be reflected in the ERAM balancing account in accordance with the procedures set forth in D.82-12-055. All TES incentive payments related to contracts executed on and after January 1, 1988, should be reflected in base rates like any other energy management expense. Finally, in implementing the change to base rate recovery of DSM program funding, Edison's CLMAC billing factor should be reduced in an amount consistent with D.87-05-021 in Edison's most recent CLMAC proceeding.

b. $2.5 Million Limit on Funding Shifts

Edison proposes to eliminate the $2.5 million limit on funding shifts within major program categories (i.e., Residential Conservation, Commercial/Industrial/Agricultural Conservation, and Load Management). Edison states that this limit, established in Edison's last general rate case (D.84-12-068), hampers its ability to respond to changing needs. Edison states that it has a demonstrated track record of implementing programs consistent with

VII. Cogeneration/Small Power Production Programs

A. Edison and PSD Recommendations

Edison has estimated the cost for its Cogeneration and Small Power Development program in 1988 to be $1,765,000. This level of funding, according to Edison, is required to maintain new QF projects already on-line and to ensure their integrated operation with the Edison system.

Edison states that it continues to be committed to the success of reasonable alternative resources as an integral part of its resource plan. According to Edison, by the end of September 1986 it had executed 407 contracts representing 7,277 MW of nameplate capacity. To more efficiently utilize QF generation, Edison states that it is currently negotiating dispatchability provisions with QFs who have executed contracts. The growth in QF generation expected by Edison into the mid-1990's will, in Edison's opinion, reduce the need to commit resources to build base load generating units in the foreseeable future.

The six major components of Edison's Cogeneration and Small Power Development program are execution of contracts, QF project development management, contract administration, regulatory interface, outreach and communication, and special studies. Edison believes these components are necessary to maintain and integrate cogeneration and small power production into the Edison electrical system. According to Edison, the implementation of these program components requires the maintenance of current staffing levels.

PSD states that its review of the Edison cogeneration and small power program indicates that Edison's efforts in signing QF projects and integrating them into the utility electric system have been successful. PSD agrees with Edison's funding request of $1,765,000 for this program, which matches the levels approved in 1985 and 1986.

CORRECTION

THIS DOCUMENT HAS

BEEN REPHOTOGRAPHED

TO ASSURE

LEGIBILITY

VII. Cogeneration/Small Power Production Programs

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Edison states that it continues to be committed to the success of reasonable alternative resources as an integral part of its resource plan. According to Edison, by the end of September 1986 it had executed 407 contracts representing 7,277 MW of nameplate capacity. To more efficiently utilize QF generation, Edison states that it is currently negotiating dispatchability provisions with QFs who have executed contracts. The growth in QF generation expected by Edison into the mid-1990's will, in Edison's opinion, reduce the need to commit resources to build base load generating units in the foreseeable future.

The six major components of Edison's Cogeneration and Small Power Development program are execution of contracts, QF project development management, contract administration, regulatory interface, outreach and communication, and special studies. Edison believes these components are necessary to maintain and integrate cogeneration and small power production into the Edison electrical system. According to Edison, the implementation of these program components requires the maintenance of current staffing levels.

PSD states that its review of the Edison cogeneration and small power program indicates that Edison's efforts in signing QF projects and integrating them into the utility electric system have been successful. PSD agrees with Edison's funding request of $1,765,000 for this program, which matches the levels approved in 1985 and 1986.

Commission policy and considers energy management an important resource alternative. Elimination of the funding limit, in Edison's view, will increase Edison's flexibility to derive the maximum benefit from energy management.

PSD, however, strongly recommends that the cap remain in place and that advice letter filings for funding shifts of $2.5 million or more continue to be required. PSD does recommend, however, that the categories be modified to give Edison more flexibility within program areas.

Specifically, PSD recommends that the current three program categories be replaced with the following six categories: (1) Energy Services and Information Programs (Residential and Non-Residential); (2) Residential and Non-Residential Conservation Incentive Programs; (3) Load Management Programs; (4) Marketing Programs (if any are funded in spite of PSD's recommendations and Edison's withdrawal of those labeled as such); (5) Measurement and Evaluation; and (6) Energy Management Support. PSD further proposes that any funding shift over $2.5 million within categories or any funding shift between the categories should be requested by an advice letter filing. PSD notes that its proposal will provide Edison with more flexibility in managing its conservation and load management program budgets since Edison will not need to submit an advice letter to shift the dollars covered by the cap.

PSD refutes Edison's assertion that PSD did not provide any evidence to support its recommended continuation of the cap on funding shifts. PSD states that the development of its new program categories was based on an independent cost-effectiveness analysis and programmatic review.

We note that the $2.5 million limit on funding shifts at issue in this proceeding has been maintained since Edison's 1983 test year general rate case. (See, D.82-12-055, D.84-12-068.) Specifically, we had intended by our prior orders to grant Edison the discretion to reallocate up to $2.5 million within its three

PSD recommends, however, that for the attrition years, during which currently pending projects will have either become operational or have been abandoned, funding should be reduced by $200,000 in 1989 and $550,000 in 1990. Edison has accepted these adjustments conditioned on the adjustment being subject to a periodic analysis on the optimal funding for the program. PSD accepts this request, with the first such report to be received on August 31, 1988.

We concur with Edison and PSD that the continued effective development of QF resources is an important goal which will permit Edison to meet its resource needs. The funding level for this program requested by Edison and to which PSD has agreed is sufficient to fund the program components. We also agree with PSD that program costs should be tracked to provide for the most cost-effective development of this resource. We therefore find reasonable and adopt the overall program funding of $1,765,000, with reductions of $200,000 in 1989 and $550,000 in 1990 if warranted on the basis of the periodic analysis to be undertaken by PSD and Edison.

basic conservation program categories. Advice letter filings were required, however, for shifts among the three major program categories or for shifts of greater than $2.5 million within the program category.

Edison now suggests that instead of improving its management flexibility, this funding limit has hampered its ability to respond to Commission conservation directives. We are slightly perplexed by this assertion, unless Edison's proposed elimination of the $2.5 million cap includes the elimination of advice letters for inter-category and intra-category funding shifts. This position is untenable especially with our increased need to control conservation and load management spending.

To enhance Edison's flexibility in managing its DSM program funding, we are at most willing to continue to maintain the $2.5 million allowance on funding shifts within the three major program categories and to reject PSD's suggestion for increasing the number of categories. PSD's suggestion would not seem to improve Edison's flexibility since advice letters would be required for every shift between categories, and the increase in categories would obviously result in an increase in the instances when advice letters would be required. We continue our admonition to Edison stated in D.84-12-068, however, that our E&C Division should be advised of all changes in program emphasis whether or not an advice letter is required. We therefore find reasonable and adopt the continuation of the three basic DSM program categories of Residential Conservation, Commercial/Industrial/Agricultural Conservation, and Load Management, and of advice letter filings for funding shifts between these three major program categories or for shifts of greater than $2.5 million within those categories.

c. <u>Energy Management Salary Budget</u>

As required by Ordering Paragraph 12 of D.84-12-068 in Edison's last general rate case, Edison has reduced the Corporate Energy Management labor budget by over 20% and provided a numerical

VIII. Bypass

On October 1, 1986, the Commission issued Rulemaking (R.) 86-10-001. This rulemaking, also known as the "3-Rs" (risk, return, and ratemaking), was intended to revise electric utility ratemaking mechanisms in response to changing conditions in the electric industry. With the issuance of D.87-05-071 in R.86-10-001, the Commission indicated that its concern with one of these changing conditions, the phenomenon known as "bypass," had become paramount.

As described in D.87-05-071, "bypass" occurs when a customer chooses to generate its own energy rather than accept the service available from the local public utility. Because of lower fossil fuel prices and revitalized generation technology, we recognized in D.87-05-071 that self-generation had become attractive to many customers especially when the utility's rates exceed the cost of self-generation. We further found, however, that this loss of customers from the system could negatively affect remaining customers who would be faced with increased rates due to the utility's fixed costs being borne by a smaller sales base. (D.87-05-071, at pp. 2-3.)

Our particular concern, as explained in D.87-05-071, is that a customer with self-generation costs exceeding the utility's short-run marginal costs will bypass the utility system, an "uneconomic" bypass. When this situation occurs, we have found that the customer's self-generation results in "an inefficient allocation of society's resources." (D.87-05-071, at p. 3.) We have also observed that when the customer is able to generate for less than the utility's long-run marginal cost, but more than the utility's short-run marginal cost, the customer should be induced to remain on the system and to postpone construction of its own facility until additional capacity is needed by the utility. (Id.)

count by job category and salary range and a description of each job category. Based on these actions, we find that Edison has complied with D.84-12-068.

d. PSD Program Definitions

PSD recommends that for future reporting requirements and applications Edison be directed to use the program definitions established and used by the PSD in this proceeding. According to PSD, its definitions use generic names rather than Edison promotional names (e.g., non-residential new construction rather than Award Building Program), distinguish between participating customer classes, and reflect the program purpose. PSD believes that this approach is essential to tracking similar programs with different names over time and to providing meaningful cost-effectiveness analyses.

We find PSD's suggestion to be meritorious. We believe that as our scrutiny of conservation programs and their cost-effectiveness has intensified so has our need to track these programs and ensure that duplicative spending does not result. In the rate case setting, such consistency is even more critical as multiple programs are reviewed and funding levels are approved. We therefore adopt the generic demand side management definitions being established in the Reporting Requirements Manual and direct Edison to use these definitions in all future rate, offset, and advice letter proceedings.

D. Adopted Results

The following table summarizes our adopted funding levels for Edison's DSM programs:

We concluded in D.87-05-071 that to address the problems created by bypass certain general solutions suggested themselves. These solutions included: (1) the efficient use of the utility's capacity helping to lower rates by spreading costs over a larger base, (2) the lowering of overall rates by bringing them closer to marginal costs, and (3) the efficient management of the system permitting the utility to act more competitively to retain existing customers and to increase sales when short-run marginal costs are low. (D.87-05-071, at p. 3.)

Guided by these basic principles, we adopted in D.87-05-071 several policies aimed at lessening the detrimental impact of bypass on the utility and its customers. These policies included a commitment to revenue allocation based on Equal Percent of Marginal Cost (EPMC), the elimination of the Attrition Rate Adjustment (ARA) for the large light and power class, the elimination of the Electric Revenue Adjustment Mechanism (ERAM) for the large light and power class, and the use of special contracts between the utilities and the customers in the large light and power class. To implement these policies, further proceedings were ordered to examine guidelines for special contracts, rate options and rate unbundling for different customer classes, and revised forecasts of sales and revenues.

In adopting these policies, however, we indicated that each was subject to the dynamics of changing utility conditions and could be altered in response to those changes. Additionally, we made clear that these policies were not aimed at diminishing our support for alternate generation, but rather to design regulatory mechanisms to promote efficient use of an integrated system of electric resources. (D.87-05-071, at p. 4.)

We believe that the appropriate forum for developing policies governing our response to bypass is clearly R.86-10-001. Those policies, however, play an important and integral role in our findings in this general rate case on issues related to marginal

Adopted 1988 Demand Side Management Program Expenses

Residential Conservation	
Residential Information	$ 1,919
Energy Management Services	4,149
Weather & Retrofit Incentives	768
Energy Eff. Home Builders	1,000
HP Water Heater/Solar Service	40
Appliance Eff. Incentives	4,105
Direct Assistance	5,470
	17,451
Non-Residential Conservation	
Non-Residential Information	767
Energy Management Services	8,029
Energy Management Incentives (Comm.)	3,446
Energy Management Incentives (Ind.)	1,227
Energy Management Incentives (Admin.)	338
New Construction	2,500
	16,307
Load Management	
AC Cycling - Residential	1,846
Pool Timer	209
DSS III	1,718
AC Cycling - Non-Residential	109
Therm. Storage/Off-Peak Cool	4,000
Interrupt./Curtailable	215
Water Storage	1,641
	9,738
Measurement & Evaluation	7,325
Support Programs	
Public Awareness	1,031
Advertising	492
Mgmt./Admin./Reg. Support	2,200
	3,723
Grand Total DSM Programs	54,544
Adjustments for Program Impacts	(350)
Grand Total DSM Programs	54,194

cost, revenue allocation, rate design, and demand side management programs. This role is reflected in both the parties' positions and our resolution of each of these issues.

Bypass, however, was made a separate issue in this proceeding by Edison's inclusion in its prepared testimony of an exhibit (Exhibit 21) intended to quantify the extent of bypass expected in the future. The study included in Exhibit 21 was later revised and the results of the new study were presented in Exhibit 21-A. Because insufficient time was available for the parties to fully review Exhibit 21-A, this exhibit was not considered to have superseded Exhibit 21, and both exhibits remained in the record in this proceeding.

Based on these exhibits, Edison is forecasting significant amounts of bypass over the next several years.[5] Edison's forecast was developed by examining several non-residential market segments which had been identified by Edison as prospective candidates for uneconomic bypass. These segments included oil refining and processing, process industries (TOU-8), assembly industries (TOU-8), and commercial (TOU-8) and general service (GS-2) customers.

While presenting no forecasts of their own, both PSD and the California Cogeneration Council (CCC) seriously questioned both studies performed by Edison. PSD cited flaws in these studies related to the method of evaluation, the assumptions used, and the information "gaps" which PSD believes "prevents the study from leading to a useful analysis." (PSD Opening Brief, at p. 107.) PSD also states that Edison has acknowledged that the studies did not include an evaluation of the customer's financial ability to

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5 In Exhibit 21-A, Edison indicated a sales reduction for the year 1992, the year on which Edison had focused, of between 9.9 BkWh, based the rate design proposed by Edison in this proceeding, and 14.3 BkWh, based on present rate design.

VII. Cogeneration/Small Power Production Programs

A. Edison and PSD Recommendations

Edison has estimated the cost for its Cogeneration and Small Power Development program in 1988 to be $1,765,000. This level of funding, according to Edison, is required to maintain new QF projects already on-line and to ensure their integrated operation with the Edison system.

Edison states that it continues to be committed to the success of reasonable alternative resources as an integral part of its resource plan. According to Edison, by the end of September 1986 it had executed 407 contracts representing 7,277 MW of nameplate capacity. To more efficiently utilize QF generation, Edison states that it is currently negotiating dispatchability provisions with QFs who have executed contracts. The growth in QF generation expected by Edison into the mid-1990's will, in Edison's opinion, reduce the need to commit resources to build base load generating units in the foreseeable future.

The six major components of Edison's Cogeneration and Small Power Development program are execution of contracts, QF project development management, contract administration, regulatory interface, outreach and communication, and special studies. Edison believes these components are necessary to maintain and integrate cogeneration and small power production into the Edison electrical system. According to Edison, the implementation of these program components requires the maintenance of current staffing levels.

PSD states that its review of the Edison cogeneration and small power program indicates that Edison's efforts in signing QF projects and integrating them into the utility electric system have been successful. PSD agrees with Edison's funding request of $1,765,000 for this program, which matches the levels approved in 1985 and 1986.

self-generate or the choice a customer would make, given limited finances, between the cogeneration alternative and other options.

The CCC similarly criticizes Edison's studies and even finds that Edison's definition of "uneconomic" bypass is flawed. Specifically, the CCC charges that Edison has failed to consider the long-term economic perspective in evaluating the benefits of self-generation. In addition to identifying errors in Edison's forecast methodology and assumptions, the CCC also argues that Edison's failure to make available to the CCC its models and data base, which Edison asserts are proprietary, renders Edison's forecasts suspect.

In addition to challenging Edison's studies, both PSD and the CCC offered their own insights into the issue of bypass. PSD concurs with the effort to follow policies like those announced in D.87-05-071. PSD also believes, however, that the ratepayer should not shoulder the responsibility for stemming uneconomic bypass alone. Specifically, PSD states that an additional mechanism for avoiding bypass, in which shareholders and the utility would have an influence and a stake, is the effective and efficient management of the system designed to reduce the utility's revenue requirement. In PSD's opinion, "ever increasing revenue requirements will, if unchecked, make all the allocation and rate design modifications moot as methods to control bypass" and will result in rates which will be "non-competitive on any basis." (PSD Opening Brief, at p. 104.)

The CCC also recognizes that measures should be taken to relieve pressures resulting from uneconomic bypass, including the immediate move to an EPMC revenue allocation for all customers. On the other hand, the CCC warns that other proposals aimed at uneconomic bypass, including Edison's contract rate proposal, should be examined with care to ensure that these "solutions" to short-term concerns do not discourage or sacrifice the long-term benefits of cogeneration and economic bypass.

PSD recommends, however, that for the attrition years, during which currently pending projects will have either become operational or have been abandoned, funding should be reduced by $200,000 in 1989 and $550,000 in 1990. Edison has accepted these adjustments conditioned on the adjustment being subject to a periodic analysis on the optimal funding for the program. PSD accepts this request, with the first such report to be received on August 31, 1988.

We concur with Edison and PSD that the continued effective development of QF resources is an important goal which will permit Edison to meet its resource needs. The funding level for this program requested by Edison and to which PSD has agreed is sufficient to fund the program components. We also agree with PSD that program costs should be tracked to provide for the most cost-effective development of this resource. We therefore find reasonable and adopt the overall program funding of $1,765,000, with reductions of $200,000 in 1989 and $550,000 in 1990 if warranted on the basis of the periodic analysis to be undertaken by PSD and Edison.

We applaud Edison's effort to quantify the effects of bypass, but, like PSD and the CCC, have grave reservations regarding the methodology and assumptions used by Edison to make its forecasts. Problems associated with ensuring the certainty of forecasted results are made more acute in dealing with a previously untested area.

We are therefore reluctant to adopt any of the results provided by Edison due to the serious questions raised regarding assumptions and approach and the parties' inability to adequately review the models and data base. Our findings in this decision relating to the use of and access to computer models in developing marginal costs, based in part on Sections 1821, et al., of the California Public Utilities Code, are equally applicable here. In summary of those findings, if the utility chooses to rely on a computer model to support testimony in an evidentiary hearing, the utility must permit access to and verification of the model and related data bases to the extent necessary for cross-examination and rebuttal.

Further, while forecasts of bypass may be helpful in the future to determine the impact of our remedial actions, we do not find that adoption of a particular estimate of bypass is necessary in this proceeding. Our decision in R.86-10-001 makes clear that we are aware of the significance and potential of uneconomic bypass and will follow policies aimed at deterring its spread. This present decision takes into account the findings of D.87-05-071 and implements them in the areas of marginal cost, revenue allocation, rate design, and load management. We believe, however, that any further study or conclusions related to the issue of bypass are appropriately left to R.86-10-001. Due to the absence of sufficient need and analytical support we do not adopt Edison's bypass estimate.

We do wish to assure the CCC and other representatives of alternate generation entities that our goal is in fact to stem the

VIII. Bypass

On October 1, 1986, the Commission issued Rulemaking (R.) 86-10-001. This rulemaking, also known as the "3-Rs" (risk, return, and ratemaking), was intended to revise electric utility ratemaking mechanisms in response to changing conditions in the electric industry. With the issuance of D.87-05-071 in R.86-10-001, the Commission indicated that its concern with one of these changing conditions, the phenomenon known as "bypass," had become paramount.

As described in D.87-05-071, "bypass" occurs when a customer chooses to generate its own energy rather than accept the service available from the local public utility. Because of lower fossil fuel prices and revitalized generation technology, we recognized in D.87-05-071 that self-generation had become attractive to many customers especially when the utility's rates exceed the cost of self-generation. We further found, however, that this loss of customers from the system could negatively affect remaining customers who would be faced with increased rates due to the utility's fixed costs being borne by a smaller sales base. (D.87-05-071, at pp. 2-3.)

Of particular concern in D.87-05-071 was "uneconomic" bypass, defined in that order as occurring when a customer with self-generation costs exceeding the utility's short-run marginal costs bypasses the utility system. Under these circumstances, we found that the customer's self-generation results in "an inefficient allocation of society's resources." (D.87-05-071, at p. 3.) We also observed that when the customer is able to generate for less than the utility's long-run marginal cost, but more than the utility's short-run marginal cost, the customer should be induced to remain on the system and to postpone construction of its own facility until additional capacity is needed by the utility. (Id.)

tide of uneconomic bypass. We will encourage, to the extent that it is required and economically efficient, self-generation based on the use of renewable resources. We believe that the precision with which we have strived to identify Edison's marginal and avoided costs will ensure the receipt of proper price signals by both customers considering bypass of the utility system and those who have already chosen self-generation.

Finally, we note PSD's concern with the effect of "ever increasing revenue requirements" on bypass. As we stated previously, efficiencies in utility management have been recognized in D.87-05-071 as a means of stemming uneconomic bypass. We believe that we have carried out this policy in this proceeding in our careful review of and ultimate findings on Edison's revenue requirements and management programs. It is our hope therefore that our adopted revenue requirement and rate design will prove effective in redressing the negative effects of bypass on Edison and its ratepayers.

We concluded in D.87-05-071 that to address the problems created by bypass certain general solutions suggested themselves. These solutions included: (1) the efficient use of the utility's capacity helping to lower rates by spreading costs over a larger base, (2) the lowering of overall rates by bringing them closer to marginal costs, and (3) the efficient management of the system permitting the utility to act more competitively to retain existing customers and to increase sales when short-run marginal costs are low. (D.87-05-071, at p. 3.)

Guided by these basic principles, we adopted in D.87-05-071 several policies aimed at lessening the detrimental impact of bypass on the utility and its customers. These policies included a commitment to revenue allocation based on Equal Percent of Marginal Cost (EPMC), the elimination of the Attrition Rate Adjustment (ARA) for the large light and power class, the elimination of the Electric Revenue Adjustment Mechanism (ERAM) for the large light and power class, and the use of special contracts between the utilities and the customers in the large light and power class. To implement these policies, further proceedings were ordered to examine guidelines for special contracts, rate options and rate unbundling for different customer classes, and revised forecasts of sales and revenues.

In adopting these policies, however, we indicated that each was subject to the dynamics of changing utility conditions and could be altered in response to those changes. Additionally, we made clear that these policies were not aimed at diminishing our support for alternate generation, but rather to design regulatory mechanisms to promote efficient use of an integrated system of electric resources. (D.87-05-071, at p. 4.)

We believe that the appropriate forum for developing policies governing our response to bypass is clearly R.86-10-001. Those policies, however, play an important and integral role in our findings in this general rate case on issues related to marginal

IX. Marginal Costs

A. Introduction

With this decision, the Commission continues its commitment to marginal cost ratemaking. Marginal cost is an economic concept which refers to the change in total costs resulting from a change in output. As applied to an electric utility, marginal cost is the change in costs resulting from a change in the number of kilowatts (kW) of capacity and kilowatt-hours (kWh) of energy produced.

Over the past six years, the Commission has used marginal costs to allocate the utility revenue requirement among customer groups and to design the rate levels for individual rate schedules within each customer group. Marginal costs are also used to measure the cost-effectiveness of resource additions, conservation, and load management programs.

Our need to rely on marginal costs for ratemaking has become more acute in recent years as the Commission seeks to ensure the financial integrity of the utility system and in turn the utility's ability to discharge its obligation to provide and maintain adequate and reasonable service. It has been the Commission's long-held view that by using marginal costs in ratesetting each customer will be provided the most accurate price signals regarding his consumption. Not only will this promote conservation and the efficient use of resources, but equity will be achieved by the utility recovering the costs of providing service to each customer in proportion to the costs that customer imposes on the utility system. By providing such cost-related rates, it is additionally our hope that the uneconomic bypass of the utility

cost, revenue allocation, rate design, and demand side management programs. This role is reflected in both the parties' positions and our resolution of each of these issues.

Bypass, however, was made a separate issue in this proceeding by Edison's inclusion in its prepared testimony of an exhibit (Exhibit 21) intended to quantify the extent of bypass expected in the future. The study included in Exhibit 21 was later revised and the results of the new study were presented in Exhibit 21-A. Because insufficient time was available for the parties to fully review Exhibit 21-A, this exhibit was not considered to have superseded Exhibit 21, and both exhibits remained in the record in this proceeding.

Based on these exhibits, Edison is forecasting significant amounts of bypass over the next several years.[5] Edison's forecast was developed by examining several non-residential market segments which had been identified by Edison as prospective candidates for uneconomic bypass. These segments included oil refining and processing, process industries (TOU-8), assembly industries (TOU-8), and commercial (TOU-8) and general service (GS-2) customers.

While presenting no forecasts of their own, both PSD and the California Cogeneration Council (CCC) seriously questioned both studies performed by Edison. PSD cited flaws in these studies related to the method of evaluation, the assumptions used, and the information "gaps" which PSD believes "prevents the study from leading to a useful analysis." (PSD Opening Brief, at p. 107.) PSD also states that Edison has acknowledged that the studies did not include an evaluation of the customer's financial ability to

5 In Exhibit 21-A, Edison indicated a sales reduction for the year 1992, the year on which Edison had focused, of between 9.9 BkWh, based the rate design proposed by Edison in this proceeding, and 14.3 BkWh, based on present rate design.

system by customers with the capability of self-generation will be averted.[6]

The three principal components of an electric utility's marginal cost are (1) the cost of providing energy, (2) the cost of meeting a customer's demand, and (3) the cost of providing customers with access to the utility system. The first of these components, marginal energy costs, measures the change in total costs caused by a kWh change in energy demand. The second component, marginal demand or capacity costs, measures the change in total costs caused by a kW change in demand. Marginal demand costs are calculated in terms of the incremental investment in physical plant needed to serve the next unit of load and are subdivided into three categories: generation, transmission, and distribution. The third and final component, marginal customer costs, measure the change in total system costs required to hook up a new customer to a utility's distribution system. Ideally, marginal customer costs should reflect the price a subscriber must pay to secure a service connection and to maintain access regardless of area load.

A variation on the theory of marginal costs is the concept of avoided costs. Avoided costs are the costs of producing additional units of energy or capacity which the utility avoids by purchasing power from another source. While marginal costs are the basis for ratesetting, federal statute (the Public Utilities Regulatory Policies Act of 1978 (PURPA)) has dictated that a utility's avoided costs are to be the basis of payments to cogenerators and small power producers (qualifying facilities (QF)) who sell their output to electric utilities. The rules governing these purchases have largely been dictated by the Commission's

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6 The subject of bypass is discussed in more detail in a separate part of this order.

self-generate or the choice a customer would make, given limited finances, between the cogeneration alternative and other options.

The CCC similarly criticizes Edison's studies and even finds that Edison's definition of "uneconomic" bypass is flawed. Specifically, the CCC charges that Edison has failed to consider the long-term economic perspective in evaluating the benefits of self-generation. In addition to identifying errors in Edison's forecast methodology and assumptions, the CCC also argues that Edison's failure to make available to the CCC its models and data base, which Edison asserts are proprietary, renders Edison's forecasts suspect.

In addition to challenging Edison's studies, both PSD and the CCC offered their own insights into the issue of bypass. PSD concurs with the effort to follow policies like those announced in D.87-05-071. PSD also believes, however, that the ratepayer should not shoulder the responsibility for stemming uneconomic bypass alone. Specifically, PSD states that an additional mechanism for avoiding bypass, in which shareholders and the utility would have an influence and a stake, is the effective and efficient management of the system designed to reduce the utility's revenue requirement. In PSD's opinion, "ever increasing revenue requirements will, if unchecked, make all the allocation and rate design modifications moot as methods to control bypass" and will result in rates which will be "non-competitive on any basis." (PSD Opening Brief, at p. 104.)

The CCC also recognizes that measures should be taken to relieve pressures resulting from uneconomic bypass, including the immediate move to an EPMC revenue allocation for all customers. On the other hand, the CCC warns that other proposals aimed at uneconomic bypass, including Edison's contract rate proposal, should be examined with care to ensure that these "solutions" to short-term concerns do not discourage or sacrifice the long-term benefits of cogeneration and economic bypass.

consolidated standard offer proceeding, Application (A.) 82-04-044, et al. However, the updating and refinement of the actual prices to be paid QFs takes place in each electric utility's general rate case or Energy Cost Adjustment Clause (ECAC) proceeding.

The similarities between marginal and avoided costs do not end with their conceptual link. Although the Commission is on the eve of finalizing the terms of a long-run standard offer in A.82-04-044, et al., the economic time frame for calculating both marginal and avoided costs within the context of the general rate case remains the "short-run." The "short-run" refers to a situation in which the utility's plant remains constant, but the operation of that plant can be varied. In the "long-run," all aspects of the economic equation can be changed including fixed assets (utility plant) and all variable inputs. In the short-run, the prices paid to qualifying facilities are based on two components--an energy payment based on the utility's cost of producing an additional kWh of energy with the resources that are on the margin and a capacity payment based on the utility's the cost of producing an additional kW of capacity in the short-run.

Previously, the Commission has indicated its intention in calculating marginal and avoided costs of achieving uniformity in the price signals impacting the economic and resource decisions made by utilities, customers, and QFs alike. This goal was realized by the Commission in Southern California Edison Company's (Edison) last general rate case by applying the same short-run methodology for the calculation of both marginal and avoided costs. (Decision (D.) 84-12-068, at p. 230.)

To the extent possible and practicable, a similar effort toward uniformity between marginal and avoided costs will be made in this decision. We recognize, however, that changes to the methodology for pricing qualifying facility power which have been adopted since the last general rate case must be taken into consideration in calculating QF payments.

We applaud Edison's effort to quantify the effects of bypass, but, like PSD and the CCC, have grave reservations regarding the methodology and assumptions used by Edison to make its forecasts. Problems associated with ensuring the certainty of forecasted results are made more acute in dealing with a previously untested area.

We are therefore reluctant to adopt any of the results provided by Edison due to the serious questions raised regarding assumptions and approach and the parties' inability to adequately review the models and data base. Our findings in this decision relating to the use of and access to computer models in developing marginal costs, based in part on Sections 1821, et al., of the California Public Utilities Code, are equally applicable here. In summary of those findings, if the utility chooses to rely on a computer model to support testimony in an evidentiary hearing, the utility must permit access to and verification of the model and related data bases to the extent necessary for cross-examination and rebuttal.

Further, while forecasts of bypass may be helpful in the future to determine the impact of our remedial actions, we do not find that adoption of a particular estimate of bypass is necessary in this proceeding. Our decision in R.86-10-001 makes clear that we are aware of the significance and potential of uneconomic bypass and will follow policies aimed at deterring its spread. This present decision takes into account the findings of D.87-05-071 and implements them in the areas of marginal cost, revenue allocation, rate design, and load management. We believe, however, that any further study or conclusions related to the issue of bypass are appropriately left to R.86-10-001. Due to the absence of sufficient need and analytical support we do not adopt Edison's bypass estimate.

We do wish to assure the CCC and other representatives of alternate generation entities that our goal is in fact to stem the

Our use and calculation of marginal costs over the past six years has been an evolutionary process. Our increasing commitment to and sophistication in developing marginal costs has been matched by the parties. The ultimate result in this decision will hopefully be greater precision in identifying these costs.

During the course of the hearings in this proceeding, a number of parties participated in litigating the issues related to marginal cost and revenue allocation. These parties included Edison, Public Staff Division (PSD), the California Cogeneration Council (CCC), the Cogenerators of Southern California (CSC), the California Manufacturers Association (CMA), the Industrial Users (IU), the California Large Energy Consumers Association and California Steel Producers Group (CLECA/CSPG), the Independent Energy Producers Association (IEP), the Federal Executive Agencies (FEA), the Association of California Water Agencies (ACWA), the California Farm Bureau Federation (Farm Bureau), and Towards Utility Rate Normalization (TURN).

B. Marginal and Avoided Cost Issues

During this proceeding, agreement was reached by Edison and PSD on a number of issues related to costing periods, marginal demand cost, marginal customer cost, and marginal cost revenue responsibility. This agreement was presented in the form of a joint exhibit (Exhibit 41). The following table, based on the joint exhibit, summarizes the areas of agreement between the two parties. No similar exhibit was presented for avoided energy costs or capacity value adjustments used for QF payments.

tide of uneconomic bypass. We will encourage, to the extent that it is required and economically efficient, self-generation based on the use of renewable resources. We believe that the precision with which we have strived to identify Edison's marginal and avoided costs will ensure the receipt of proper price signals by both customers considering bypass of the utility system and those who have already chosen self-generation.

Finally, we note PSD's concern with the effect of "ever increasing revenue requirements" on bypass. As we stated previously, efficiencies in utility management have been recognized in D.87-05-071 as a means of stemming uneconomic bypass. We believe that we have carried out this policy in this proceeding in our careful review of and ultimate findings on Edison's revenue requirements and management programs. It is our hope therefore that our adopted revenue requirement and rate design will prove effective in redressing the negative effects of bypass on Edison and its ratepayers.

SUMMARY OF PSD AND EDISON AGREEMENT
MARGINAL COST AND MARGINAL COST REVENUE RESPONSIBILITY

Issue	Agreement
Marginal Generation Cost:	
Methodology	CT Proxy
Total Investment Cost	$614.96/kW
O&M Cost	PSD Escalation
Economic Carrying Charges	10.04% and 10.29%
Marginal Transmission Cost:	
Methodology	Regression Analysis
Total Investment Cost	$263.40/kW
O&M Cost	PSD Escalation
Economic Carrying Charge	10.90%
Marginal Distribution Cost:	
Methodology	Regression Analysis of Non-TSM Investment
Total Investment Cost	$240.00/kW
O&M Cost	PSD Escalation
Economic Carrying Cost	13.08%
Primary Voltage Portion	86.3%
CIAC Adjustment	Included
Marginal Customer Cost:	
Methodology	Typical New Customer, T-S-M Accounts
O&M Allocation	On Capital Investment
O&M Cost	PSD Escalation
Economic Carrying Charge	13.08%
Marginal Energy Cost:	
Variable O&M	0.3¢/kWh
Line Loss Factors	Revised Average Losses
Costing Periods:	
Seasons	Four Month Summer
Summer On-Peak	12:00 n - 6:00 pm
Winter On- and Mid-Peak	Combine Into One Period
Other	Same as Current
Revenue Responsibility Allocation:	
Coincident/Non-Coincident Demand-Classification:	
Generation	100%/0%
Transmission	93%/7%
Primary Distribution	40%/60%
Secondary Distribution	0%/100%
Coincident Demand Allocation	1988 LOLP
Non-Coincident Demand Allocation	Adjusted NC Demand
Franchise Fees & Uncollectible Accts.	Includes FF

IX. Marginal Costs

A. Introduction

With this decision, the Commission continues its commitment to marginal cost ratemaking. Marginal cost is an economic concept which refers to the change in total costs resulting from a change in output. As applied to an electric utility, marginal cost is the change in costs resulting from a change in the number of kilowatts (kW) of capacity and kilowatt-hours (kWh) of energy produced.

Over the past six years, the Commission has used marginal costs to allocate the utility revenue requirement among customer groups and to design the rate levels for individual rate schedules within each customer group. Marginal costs are also used to measure the cost-effectiveness of resource additions, conservation, and load management programs.

Our need to rely on marginal costs for ratemaking has become more acute in recent years as the Commission seeks to ensure the financial integrity of the utility system and in turn the utility's ability to discharge its obligation to provide and maintain adequate and reasonable service. It has been the Commission's long-held view that by using marginal costs in ratesetting each customer will be provided the most accurate price signals regarding his consumption. Not only will this promote conservation and the efficient use of resources, but equity will be achieved by the utility recovering the costs of providing service to each customer in proportion to the costs that customer imposes on the utility system. By providing such cost-related rates, it is additionally our hope that the uneconomic bypass of the utility

The agreement reached by Edison and PSD represents actual agreements on both methodology and results, as well as compromises on such issues as costing periods, marginal customer costs, and marginal cost revenue responsibility. With respect to the latter two areas, Edison and PSD found that the results of their different methodological approaches did not produce significantly different overall results. While PSD and Edison each continue to believe that their own methodologies are superior, agreement to use the results of one of the parties was reached to avoid protracted disputes on issues of minor direct impact on ratepayers. The table reflects that no agreement was reached on the calculation of the incremental energy rate (IER) or the marginal fuel price.

Despite this agreement between Edison and PSD, many parties took issue with both the agreement and even the original positions of Edison and PSD. Because of this circumstance, issues remain even though they were the subject of an agreement between PSD and Edison.

In this proceeding, the issues which were litigated and briefed by the parties related to the following areas: (1) the calculation of marginal and avoided energy costs, including the modeling approach and the assumptions to be used; (2) the calculation of marginal demand and avoided capacity cost; (3) the calculation of marginal distribution and customer costs; and (4) the appropriate costing periods to be used. Each of these areas will be examined with respect to the concepts involved, the specific issues raised, and the parties' positions on those issues.

C. Marginal and Avoided Energy Costs

1. Background

Marginal energy cost is the cost of producing an additional kWh of electricity. Marginal energy costs reflect the change in a utility's total operating costs due to an incremental change in energy demand. Changes in total operating costs include fuel expenses, variable operations and maintenance (O&M) costs, and

system by customers with the capability of self-generation will be averted.[6]

The three principal components of an electric utility's marginal cost are (1) the cost of providing energy, (2) the cost of meeting a customer's demand, and (3) the cost of providing customers with access to the utility system. The first of these components, marginal energy costs, measures the change in total costs caused by a kWh change in energy demand. The second component, marginal demand or capacity costs, measures the change in total costs caused by a kW change in demand. Marginal demand costs are calculated in terms of the incremental investment in physical plant needed to serve the next unit of load and are subdivided into three categories: generation, transmission, and distribution. The third and final component, marginal customer costs, measure the change in total system costs required to hook up a new customer to a utility's distribution system. Ideally, marginal customer costs should reflect the price a subscriber must pay to secure a service connection and to maintain access regardless of area load.

A variation on the theory of marginal costs is the concept of avoided costs. Avoided costs are the costs of producing additional units of energy or capacity which the utility avoids by purchasing power from another source. While marginal costs are the basis for ratesetting, federal statute (the Public Utilities Regulatory Policies Act of 1978 (PURPA)) has dictated that a utility's avoided costs are to be the basis of payments to cogenerators and small power producers (qualifying facilities (QF)) who sell their output to electric utilities. The rules governing these purchases have largely been dictated by the Commission's

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6 The subject of bypass is discussed in more detail in a separate part of this order.

purchase power costs. The avoided, as opposed to marginal, energy cost would measure the cost the utility would have incurred to produce an additional kWh but for the presence of the QF.

Both marginal and avoided energy costs vary with the type of plant used to serve a particular load at a specific point in time and the type of fuel used to operate the plant. Marginal and avoided energy costs are therefore calculated using the same basic approach. Specifically, the generating unit which would produce the extra kWh (the marginal unit) is identified. The utility's generating efficiency at the margin is then measured in terms of an IER which is multiplied by the cost of the fuel which would be used to operate the marginal unit (incremental fuel cost). This calculation, which for the test year in a general rate case requires a forecasting of both the IER and the incremental fuel price, yields the marginal or avoided energy cost. Since costs vary according to when the energy is produced, marginal and avoided energy costs are calculated on a time differentiated basis by both time of day and by season.[7]

To provide the necessary forecast of marginal and avoided energy costs, the parties have come to rely increasingly on production cost models. Production cost models simulate the manner in which utility resources meet system loads. This simulation is driven by the resource and load assumptions which are chosen as inputs into the model. These inputs generally operate to produce a least cost result, using available resources (utility plant, QF, or purchased power) in the most economical fashion.

7 Marginal costs are differentiated by time of day between on-peak, mid-peak, and off-peak periods with defined hours, and by season, between summer and winter. The same basic daily and seasonal periods apply to avoided costs. In this proceeding, however, the IEP has proposed that for QF pricing a super off-peak period (1:00 a.m. to 5:00 p.m. daily) be added.

consolidated standard offer proceeding, Application (A.) 82-04-044, et al. However, the updating and refinement of the actual prices to be paid QFs takes place in each electric utility's general rate case or Energy Cost Adjustment Clause (ECAC) proceeding.

The similarities between marginal and avoided costs do not end with their conceptual link. Although the Commission is on the eve of finalizing the terms of a long-run standard offer in A.82-04-44, et al., the economic time frame for calculating both marginal and avoided costs within the context of the general rate case remains the "short-run." The "short-run" refers to a situation in which the utility's plant remains constant, but the operation of that plant can be varied. In the "long-run," all aspects of the economic equation can be changed including fixed assets (utility plant) and all variable inputs. In the short-run, the prices paid to qualifying facilities are based on two components--an energy payment based on the utility's cost of producing an additional kWh of energy with the resources that are on the margin and a capacity payment based on the utility's the cost of producing an additional kW of capacity in the short-run.

Previously, the Commission has indicated its intention in calculating marginal and avoided costs of achieving uniformity in the price signals impacting the economic and resource decisions made by utilities, customers, and QFs alike. This goal was realized by the Commission in Southern California Edison Company's (Edison) last general rate case by applying the same short-run methodology for the calculation of both marginal and avoided costs. (Decision (D.) 84-12-068, at p. 230.)

To the extent possible and practicable, a similar effort toward uniformity between marginal and avoided costs will be made in this decision. We recognize, however, that changes to the methodology for pricing qualifying facility power which have been adopted since the last general rate case must be taken into consideration in calculating QF payments.

Both Edison and PSD have agreed that the same approach and input assumptions should be used in this proceeding for determining the IER used in both the marginal and avoided energy cost calculations. This position is based in part on the Commission's endorsement of such uniformity in the last Edison general rate case (D.84-12-068, at p. 252.) The methodologies chosen by Edison and PSD permit such a result by being suitable, in their view, for calculating both marginal and avoided energy costs.

Since the last Edison general rate case, however, the Commission has recognized a factor which may be taken into consideration in calculating IERs for QF pricing, but which is not required in calculating the IER used to produce marginal energy costs. (See D.85-07-022.) Specifically, for the long-run standard offer for purchases from QFs, the Commission has determined that the IER should reflect the fact that QFs constitute not just the source for replacing the incremental unit of energy avoided, but also constitute a significant and growing portion of the total resources on which the utility resource plan relies. To capture this occurrence, the Commission has endorsed the use of a "QF In/QF Out" methodology, as opposed to a "QF In" methodology, for the long-run standard offer.

A "QF In" or marginal energy cost simulation essentially assumes that existing QFs (those operating prior to the beginning of the test year) are existing resources, and the IER is developed to include them. The "QF In/QF Out" simulation involves two model runs. As defined by D.85-07-022, the first run determines the total cost of producing power without QFs who will receive the short-run marginal cost price. The second run determines the total cost of producing power with the QFs who receive the short-run marginal cost price. The difference between these two cost runs produces an estimate of the short-run costs that the utility can

Our use and calculation of marginal costs over the past six years has been an evolutionary process. Our increasing commitment to and sophistication in developing marginal costs has been matched by the parties. The ultimate result in this decision will hopefully be greater precision in identifying these costs.

During the course of the hearings in this proceeding, a number of parties participated in litigating the issues related to marginal cost and revenue allocation. These parties included Edison, Public Staff Division (PSD), the California Cogeneration Council (CCC), the Cogenerators of Southern California (CSC), the California Manufacturers Association (CMA), the Industrial Users (IU), the California Large Energy Consumers Association and California Steel Producers Group (CLECA/CSPG), the Independent Energy Producers Association (IEP), the Federal Executive Agencies (FEA), the Association of California Water Agencies (ACWA), the California Farm Bureau Federation (Farm Bureau), and Towards Utility Rate Normalization (TURN).

B. <u>Marginal and Avoided Cost Issues</u>

During this proceeding, agreement was reached by Edison and PSD on a number of issues related to costing periods, marginal demand cost, marginal customer cost, and marginal cost revenue responsibility. This agreement was presented in the form of a joint exhibit (Exhibit 41). The following table, based on the joint exhibit, summarizes the areas of agreement between the two parties. No similar exhibit was presented for avoided energy costs or capacity value adjustments used for QF payments.

avoid by purchasing QF power. (D.85-07-022, at p. 55.)[8] At issue in this proceeding is whether the "QF In/QF Out" methodology can be used to calculate the IER used to develop short-run avoided costs and whether those "QF In/QF Out" methodologies proposed by the parties in this proceeding are consistent with prior Commission orders.

With this background, it is apparent that the two controlling factors in determining a utility's marginal and avoided energy costs are invariably the model or computational approach used and the assumptions made in calculating the IER and incremental fuel cost. It is in fact these subjects which are at issue in this proceeding.

2. Parties Positions

a. Models and Modeling Approaches

While the parties were unanimous in their support for using production cost models to calculate marginal and avoided energy costs, the same unanimity did not apply to identifying which model or associated methodology to use. Certain parties also expressed concerned with respect to their access to the production cost model and the data which Edison used.

For the calculation of both marginal and avoided energy costs, Edison relied on its PROMOD production costing model and the "zero-intercept methodology," a "QF-in" approach. The purpose of the zero intercept methodology is to reflect start-up and no-load

8 The IER is determined by the change in total energy in British thermal units (Btu) in the two simulations divided by the change in total gigawatt-hours (gWh) between the two simulations.

SUMMARY OF PSD AND EDISON AGREEMENT
MARGINAL COST AND MARGINAL COST REVENUE RESPONSIBILITY

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Total Investment Cost	$614.96/kW
O&M Cost	PSD Escalation
Economic Carrying Charges	10.04% and 10.29%
Marginal Transmission Cost:	
Methodology	Regression Analysis
Total Investment Cost	$263.40/kW
O&M Cost	PSD Escalation
Economic Carrying Charge	10.90%
Marginal Distribution Cost:	
Methodology	Regression Analysis of Non-TSM Investment
Total Investment Cost	$240.00/kW
O&M Cost	PSD Escalation
Economic Carrying Cost	13.08%
Primary Voltage Portion	86.3%
CIAC Adjustment	Included
Marginal Customer Cost:	
Methodology	Typical New Customer, T-S-M Accounts
O&M Allocation	On Capital Investment
O&M Cost	PSD Escalation
Economic Carrying Charge	13.08%
Marginal Energy Cost:	
Variable O&M	0.3¢/kWh
Line Loss Factors	Revised Average Losses
Costing Periods:	
Seasons	Four Month Summer
Summer On-Peak	12:00 n - 6:00 pm
Winter On- and Mid-Peak	Combine Into One Period
Other	Same as Current
Revenue Responsibility Allocation:	
Coincident/Non-Coincident Demand-Classification:	
Generation/	100%/0%
Transmission	93%/7%
Primary Distribution	40%/60%
Secondary Distribution	0%/100%
Coincident Demand Allocation	1988 LOLP
Non-Coincident Demand Allocation	Adjusted NC Demand
Franchise Fees & Uncollectible Accts.	Includes FF

fuel expenses[9] which are costs avoided by QFs, but not included in the calculation of the marginal energy costs directly produced by PROMOD.

PSD performed its marginal and avoided energy cost analysis using the Incremental Analysis Model (IAM) in conjunction with the Production Cost Analysis Model (PCAM). PSD presented both a "QF In/QF Out" and a "QF In" simulation. PSD recommended, however, that the "QF In" approach be used in the general rate case for calculating both marginal and avoided energy costs until a final Commission determination in the consolidated standard offer proceeding (A.82-04-044, et al.) on the propriety of using the "QF In/QF Out" methodology to calculate short-run avoided energy costs. PSD adjusted its marginal and avoided energy costs for start-up and no-load fuel expenses, which are not reflected in the PCAM calculations, by using recorded values derived from an Edison study.

Two interested parties, IEP and CCC, also presented production cost model results. Each chose a model developed by the Environmental Defense Fund called ELFIN. Additionally, both parties included a separate upward adjustment for start-up and no-load fuel expense based on the same recorded Edison values used by PSD. Both parties also proposed the use of a similar "QF In/QF

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9 No-load costs are the costs of an incremental addition of load incurred at times other than periods of incremental demand. For example, if dispatching a unit to meet a peak load requires more off-peak generation, the fuel burned in the off-peak hours to make a plant available for on-peak use is really an on-peak expense and thus a no-load cost.

Start-up costs are the costs for fuel burned to bring an incremental unit on line to meet load before the unit generates electricity. While fuel costs attributable to start-ups represent a relatively small portion of total fuel costs, start-ups may be a significant portion of marginal costs.

The agreement reached by Edison and PSD represents actual agreements on both methodology and results, as well as compromises on such issues as costing periods, marginal customer costs, and marginal cost revenue responsibility. With respect to the latter two areas, Edison and PSD found that the results of their different methodological approaches did not produce significantly different overall results. While PSD and Edison each continue to believe that their own methodologies are superior, agreement to use the results of one of the parties was reached to avoid protracted disputes on issues of minor direct impact on ratepayers. The table reflects that no agreement was reached on the calculation of the incremental energy rate (IER) or the marginal fuel price.

Despite this agreement between Edison and PSD, many parties took issue with both the agreement and even the original positions of Edison and PSD. Because of this circumstance, issues remain even though they were the subject of an agreement between PSD and Edison.

In this proceeding, the issues which were litigated and briefed by the parties related to the following areas: (1) the calculation of marginal and avoided energy costs, including the modeling approach and the assumptions to be used; (2) the calculation of marginal demand and avoided capacity cost; (3) the calculation of marginal distribution and customer costs; and (4) the appropriate costing periods to be used. Each of these areas will be examined with respect to the concepts involved, the specific issues raised, and the parties' positions on those issues.

C. Marginal and Avoided Energy Costs

1. Background

Marginal energy cost is the cost of producing an additional kWh of electricity. Marginal energy costs reflect the change in a utility's total operating costs due to an incremental change in energy demand. Changes in total operating costs include fuel expenses, variable operations and maintenance (O&M) costs, and

out" methodology. The position of the CCC was endorsed by another interested party, the CSC.

(1) Edison

It is Edison's position that only its PROMOD model coupled with the use of the zero-intercept methodology, without an adjustment for start-up and no-load fuel expense, produces reasonable IERs and ultimately reasonable marginal and avoided energy costs. According to Edison, the "zero-intercept" methodology, used to capture start-up and no-load fuel expenses, starts with a base case load forecast that is then both increased and decreased for all hours in each mid-peak and on-peak costing period to determine the impact on marginal oil and gas requirements. The "zero-intercept" of a curve representing the changes in marginal oil and gas requirements due to the changes in the load forecast represents the level of marginal heat rates at the base case level of the load in the test year.

In this proceeding, Edison implemented its zero-intercept methodology by making a total of five production cost model runs: a base case run and four runs which reflect the varying of on-peak and mid-peak loads by plus and minus 500 megawatts (MW). Edison believes that its choice of plus and minus 500 MW for the "zero-intercept" methodology produces reasonable results. While Edison can cite no mathematical study to support its position, Edison believes that its use of the 500 MW increment is supported by its considerable experience with production cost modeling. Further, the closeness with which the "zero-intercept" methodology matches the recent historical periods, in Edison's view, substantiates the choice of the 500 MW increment and the methodology itself.

Edison sees several additional benefits in using the "zero-intercept" methodology. Among them, Edison states that only the "zero-intercept" methodology, of those proposed, produces

purchase power costs. The avoided, as opposed to marginal, energy cost would measure the cost the utility would have incurred to produce an additional kWh but for the presence of the QF.

Both marginal and avoided energy costs vary with the type of plant used to serve a particular load at a specific point in time and the type of fuel used to operate the plant. Marginal and avoided energy costs are therefore calculated using the same basic approach. Specifically, the generating unit which would produce the extra kWh (the marginal unit) is identified. The utility's generating efficiency at the margin is then measured in terms of an IER which is multiplied by the cost of the fuel which would be used to operate the marginal unit (incremental fuel cost). This calculation, which for the test year in a general rate case requires a forecasting of both the IER and the incremental fuel price, yields the marginal or avoided energy cost. Since costs vary according to when the energy is produced, marginal and avoided energy costs are calculated on a time differentiated basis by both time of day and by season.[7]

To provide the necessary forecast of marginal and avoided energy costs, the parties have come to rely increasingly on production cost models. Production cost models simulate the manner in which utility resources meet system loads. This simulation is driven by the resource and load assumptions which are chosen as inputs into the model. These inputs generally operate to produce a least cost result, using available resources (utility plant, QF, or purchased power) in the most economical fashion.

7 Marginal costs are differentiated by time of day between on-peak, mid-peak, and off-peak periods with defined hours, and by season, between summer and winter. The same basic daily and seasonal periods apply to avoided costs. In this proceeding, however, the IEP has proposed that for QF pricing a super off-peak period (1:00 a.m. to 5:00 p.m. daily) be added.

time-differentiated IERs. Further, Edison notes that the "zero-intercept" methodology was previously adopted in Edison's last general rate case (D.84-12-068).

With respect to the proposals of the other parties, Edison believes that errors in PSD's PCAM modeling exist which are too severe to accept PSD's PCAM results as accurate for future planning or pricing purposes. Specifically, Edison asserts that PCAM modeling of unit dispatch is not correct and that a comparison of PSD's PCAM modeling with that of other parties shows PSD's results to be substantially at variance with the results of other parties' modeling.

Edison's greatest concerns regarding modeling and related methodology are reserved for the proposals made by IEP and the CCC. Specifically, Edison takes issue with the "QF In/QF Out" methodologies proposed by IEP and CCC. Edison argues that (1) the "QF in/QF out" method adopted by the Commission in D.85-07-022 applies to long-run standard offers while IEP and CCC apply the approach to short-run standard offers and (2) the "QF in/QF out" method adopted in D.85-07-022 excludes in one run and includes in the other only <u>future</u> QFs (those QFs expected to sign up for the contract in question during the period being forecast). Edison asserts that IEP and CCC exclude in "QFs out" and include in "QFs in" not only the future QFs, but also existing QFs who already have contracts, a position at odds, in Edison's opinion, with D.85-07-022.

Edison believes that the "fundamental flaw" of the IEP and CCC proposals is that by analyzing "QF In/QF Out" in a static, short-run context, IEP and CCC ignore that short-run standard offer QFs can result in deferring utility resources. In Edison's view using the "QF In/QF Out" methodology to set prices to all existing QFs would result in over-payments due to artificially high IERs, since the utility would have installed its own resources to lower IERs in the absence of these existing QFs.

Both Edison and PSD have agreed that the same approach and input assumptions should be used in this proceeding for determining the IER used in both the marginal and avoided energy cost calculations. This position is based in part on the Commission's endorsement of such uniformity in the last Edison general rate case (D.84-12-068, at p. 252.) The methodologies chosen by Edison and PSD permit such a result by being suitable, in their view, for calculating both marginal and avoided energy costs.

Since the last Edison general rate case, however, the Commission has recognized a factor which may be taken into consideration in calculating IERs for QF pricing, but which is not required in calculating the IER used to produce marginal energy costs. (See D.85-07-022.) Specifically, for the long-run standard offer for purchases from QFs, the Commission has determined that the IER should reflect the fact that QFs constitute not just the source for replacing the incremental unit of energy avoided, but also constitute a significant and growing portion of the total resources on which the utility resource plan relies. To capture this occurrence, the Commission has endorsed the use of a "QF In/QF Out" methodology, as opposed to a "QF In" methodology, for the long-run standard offer.

A "QF In" or marginal energy cost simulation essentially assumes that existing QFs (those operating prior to the beginning of the test year) are existing resources, and the IER is developed to include them. The "QF In/QF Out" simulation involves two model runs. As defined by D.85-07-022, the first run determines the total cost of producing power without QFs who will receive the short-run marginal cost price. The second run determines the total cost of producing power with the QFs who receive the short-run marginal cost price. The difference between these two cost runs produces an estimate of the short-run costs that the utility can

It is Edison's position that the issue of whether "QF In/QF Out" should be extended to pricing for short-run standard offer QFs is an issue to be resolved in the consolidated standard offer proceeding, A.82-04-044, et al. Until that time, Edison recommends that the zero-intercept methodology continue to be used for short-run marginal cost pricing in the general rate case. Edison disputes the precedential effect of the "QF In/QF Out" methodology being adopted in recent general rate cases. Edison observes that in the San Diego Gas & Electric Company (SDG&E) general rate case, SDG&E had proposed a "QF In/QF Out" methodology. Additionally, Edison states that D.86-12-071, in which the Commission adopted such a methodology for QF pricing for Pacific Gas and Electric Company (PG&E), was specifically intended not to be precedential.[10]

With respect to model and methodological adjustments made by the other parties, Edison is critical of IEP and CCC's external adjustment to the ELFIN production cost runs to account for start-up and no-load costs. Edison notes that most (i.e., 95%) of the adjustment is related to no-load fuel costs. Edison states that such an adjustment of ELFIN results is unnecessary since the ELFIN runs already capture the no-load fuel expense by including as an input the first production block for each oil/gas unit as an average value. Edison states that the average value, as opposed to the incremental value, reflects no-load fuel expenses associated

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10 If a "QF In/QF Out" methodology is adopted, Edison states that the Commission may be required to determine the quantity of QF production removed from the "QFs In" scenario in order to develop the "QFs Out" scenario. Edison believes that the CCC erred in its estimate of 76% of QF production receiving short-run standard offer energy prices and removing this amount of QF production. According to Edison, this estimate assumes that all non-standard contracts are variable priced and thereby overstates the amount of variable priced QF production.

avoid by purchasing QF power. (D.85-07-022, at p. 55.)[8] At issue in this proceeding is whether the "QF In/QF Out" methodology can be used to calculate the IER used to develop short-run avoided costs and whether those "QF In/QF Out" methodologies proposed by the parties in this proceeding are consistent with prior Commission orders.

With this background, it is apparent that the two controlling factors in determining a utility's marginal and avoided energy costs are invariably the model or computational approach used and the assumptions made in calculating the IER and incremental fuel cost. It is in fact these subjects which are at issue in this proceeding.

2. Parties Positions

a. Models and Modeling Approaches

While the parties were unanimous in their support for using production cost models to calculate marginal and avoided energy costs, the same unanimity did not apply to identifying which model or associated methodology to use. Certain parties also expressed concerned with respect to their access to the production cost model and the data which Edison used.

For the calculation of both marginal and avoided energy costs, Edison relied on its PROMOD production costing model and the "zero-intercept methodology," a "QF-in" approach. The purpose of the zero intercept methodology is to reflect start-up and no-load

8 The IER is determined by the change in total energy in British thermal units (Btu) in the two simulations divided by the change in total gigawatt-hours (gWh) between the two simulations.

with the operation of the unit at its minimum loading level. Edison notes that this level is the same as that at which specific resources are forced to remain on-line as "must-run" units, which is when the no-load fuel expense is incurred. For these reasons, it is Edison's opinion that IEP's and the CCC's separate adjustment for no-load fuel expenses double-counts these expenses.

Edison, however, does not find PSD in error in making an adjustment for no-load and start-up costs for its PCAM analysis since PSD's modeling results reflect an instantaneous marginal energy cost calculation for which such an adjustment is appropriate. Edison objects, however, to PSD's suggestion that the Commission should require further investigation of start-up and no-load fuel expenses in future proceedings since all parties adopted the results of Edison's studies and PSD's problems seemed limited to the need for additional back-up documentation. Edison is willing to provide the information, but does not feel that a mandate to conduct an additional study is warranted.

Finally, Edison responds to concerns regarding the access by other parties to PROMOD and data related to its use. Edison states that it fully complied with the statutory requirements by disclosing data bases, input and output information, and meeting with intervenors to provide them all information "to the extent necessary for cross-examination or rebuttal" (Section 1822(a)). On the subject of the timeliness of data responses, Edison cites the substantial time constraints that face all parties due to the strict schedule to which a general rate case must adhere. Edison believes that given those time constraints, Edison used its best efforts to respond fully and on a timely basis.

(2) PSD

Like Edison, PSD proposes that the Commission use the same methodology to calculate both marginal and avoided energy

fuel expenses[9] which are costs avoided by QFs, but not included in the calculation of the marginal energy costs directly produced by PROMOD.

PSD performed its marginal and avoided energy cost analysis using the Incremental Analysis Model (IAM) in conjunction with the Production Cost Analysis Model (PCAM). PSD presented both a "QF In/QF Out" and a "QF In" simulation. PSD recommended, however, that the "QF In" approach be used in the general rate case for calculating both marginal and avoided energy costs until a final Commission determination in the consolidated standard offer proceeding (A.82-04-44, et al.) on the propriety of using the "QF In/QF Out" methodology to calculate short-run avoided energy costs. PSD adjusted its marginal and avoided energy costs for start-up and no-load fuel expenses, which are not reflected in the PCAM calculations, by using recorded values derived from an Edison study.

Two interested parties, IEP and CCC, also presented production cost model results. Each chose a model developed by the Environmental Defense Fund called ELFIN. Additionally, both parties included a separate upward adjustment for start-up and no-load fuel expense based on the same recorded Edison values used by PSD. Both parties also proposed the use of a similar "QF In/QF

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9 No-load costs are the costs of an incremental addition of load incurred at times other than periods of incremental demand. For example, if dispatching a unit to meet a peak load requires more off-peak generation, the fuel burned in the off-peak hours to make a plant available for on-peak use is really an on-peak expense and thus a no-load cost.

Start-up costs are the costs for fuel burned to bring an incremental unit on line to meet load before the unit generates electricity. While fuel costs attributable to start-ups represent a relatively small portion of total fuel costs, start-ups may be a significant portion of marginal costs.

costs. PSD similarly cites this Commission's decision endorsing such an approach in Edison's last general rate case (D.84-12-068).

To accomplish this goal, PSD believes that its modeling approach based on the combined use of the PCAM/IAM models was the most accurate forecasting tool presented in the proceeding. This approach involves the use of two separate input files for resources. These two files represent resources which are either "energy limited" (Edison's hydro and certain firm hydro purchases) or "capacity limited" (all steam units, combustion turbines, fossil purchases). Purchases are placed in one or the other files depending on their characteristics.

PSD believes that modeling the characteristics of virtually any resource type, including economy energy, pumped storage, and different hydro types, provides a great deal of flexibility. Units can be dispatched economically, in a predetermined order, or economically with alterations to reflect dispatch limits such as for QFs, "must run" units, and purchased power. PSD states that its model can calculate on-, mid- and off-peak marginal energy costs for up to 20 rate periods and reports IERs and unit data on all modeled resources.

PSD states that its model directly calculates the IERs and marginal costs for all costing periods. Only one adjustment is made external to the model and that is an adjustment to the on-peak incremental energy rate to reflect start-up and no-load fuel. In making its adjustment, PSD utilized a detailed study performed by Edison on the impact of start-up and no-load fuel costs using historic data. PSD believes the use of Edison's study of historic start-up and no-load fuel relationships provides the most accurate means of forecasting those costs.

With respect to the models and approaches used by the other parties, PSD notes that, unlike IAM/PCAM, the PROMOD model used by Edison does not produce a direct calculation of marginal energy costs for all costing periods. Instead, PROMOD is

Out" methodology. The position of the CCC was endorsed by another interested party, the CSC.

(1) Edison

It is Edison's position that only its PROMOD model coupled with the use of the zero-intercept methodology, without an adjustment for start-up and no-load fuel expense, produces reasonable IERs and ultimately reasonable marginal and avoided energy costs. According to Edison, the "zero-intercept" methodology, used to capture start-up and no-load fuel expenses, starts with a base case load forecast that is then both increased and decreased for all hours in each mid-peak and on-peak costing period to determine the impact on marginal oil and gas requirements. The "zero-intercept" of a curve representing the changes in marginal oil and gas requirements due to the changes in the load forecast represents the level of marginal heat rates at the base case level of the load in the test year.

In this proceeding, Edison implemented its zero-intercept methodology by making a total of five production cost model runs: a base case run and four runs which reflect the varying of on-peak and mid-peak loads by plus and minus 500 megawatts (MW). Edison believes that its choice of plus and minus 500 MW for the "zero-intercept" methodology produces reasonable results. While Edison can cite no mathematical study to support its position, Edison believes that its use of the 500 MW increment is supported by its considerable experience with production cost modeling. Further, the closeness with which the "zero-intercept" methodology matches the recent historical periods, in Edison's view, substantiates the choice of the 500 MW increment and the methodology itself.

Edison sees several additional benefits in using the "zero-intercept" methodology. Among them, Edison states that only the "zero-intercept" methodology, of those proposed, produces

used directly to compute only off-peak marginal costs with the "zero intercept" methodology being used to calculate on- and mid-peak marginal energy costs.

Additionally, PSD questions and considers arbitrary Edison's use of the plus and minus 500 MW variations of on-peak and mid-peak loads in developing marginal energy costs for those time period. PSD criticizes the lack of scientific basis for the use of this particular increment other than Edison's assertion that the adjustment yields more reasonable results than the adjustment is not made. PSD also notes that the plus and minus 500 MW adjustment in this case differs from Edison's last general rate case in which two alternative adjustments were used--+/- 400 MW and +/- 800 MW.

On the subject of the use of ELFIN by IEP and the CCC, PSD states that it uses ELFIN extensively for resource planning purposes and for the long-run marginal costs used in evaluating the cost-effectiveness of resource additions and demand side management proposals. It is not clear to the PSD, however, that ELFIN is capable of computing marginal energy costs for various time periods. While there are no obvious inherent problems, PSD notes that the ELFIN simulations produced consistently higher incremental energy rates than PSD or Edison without an explanation.

PSD also references ELFIN's potential for double-counting of start-up and no-load fuel. PSD notes in particular IEP's testimony that ELFIN uses average heat rates at the minimum MW level of a unit, thereby accounting for no-load costs. If the average heat rate option is used on ELFIN then an external adjustment of start-up and no-load Btus should not be made to the IER.

With respect to the calculation of avoided energy payments for QF pricing, PSD supports a "QF In" approach. In doing so, PSD points out that the "QF In" approach was the one last used for Edison. In addition, while the Commission appears to have

time-differentiated IERs. Further, Edison notes that the "zero-intercept" methodology was previously adopted in Edison's last general rate case (D.84-12-068).

With respect to the proposals of the other parties, Edison believes that errors in PSD's PCAM modeling exist which are too severe to accept PSD's PCAM results as accurate for future planning or pricing purposes. Specifically, Edison asserts that PCAM modeling of unit dispatch is not correct and that a comparison of PSD's PCAM modeling with that of other parties shows PSD's results to be substantially at variance with the results of other parties' modeling.

Edison's greatest concerns regarding modeling and related methodology are reserved for the proposals made by IEP and the CCC. Specifically, Edison takes issue with the "QF In/QF Out" methodologies proposed by IEP and CCC. Edison argues that (1) the "QF in/QF out" method adopted by the Commission in D.85-07-022 applies to long-run standard offers while IEP and CCC apply the approach to short-run standard offers and (2) the "QF in/QF out" method adopted in D.85-07-022 excludes in one run and includes in the other only <u>future</u> QFs (those QFs expected to sign up for the contract in question during the period being forecast). Edison asserts that IEP and CCC exclude in "QFs out" and include in "QFs in" not only the future QFs, but also existing QFs who already have contracts, a position at odds, in Edison's opinion, with D.85-07-022.

Edison believes that the "fundamental flaw" of the IEP and CCC proposals is that by analyzing "QF In/QF Out" in a static, short-run context, IEP and CCC ignore that short-run standard offer QFs can result in deferring utility resources. In Edison's view using the "QF In/QF Out" methodology to set prices to all existing QFs would result in over-payments due to artificially high IERs, since the utility would have installed its own resources to lower IERs in the absence of these existing QFs.

chosen the results from a "QF In/QF Out" simulation for the most recent PG&E test year, the PSD does not believe that the Commission expressed any commitment to that method. Thus, the PSD recommends that until the Commission makes it clear as to what approach is to be utilized, consistency requires the continued use of the "QF In" method.

Recognizing the possibility of a "QF In/QF Out" approach being adopted in this proceeding, PSD, however, also offered results from using such a methodology. The "QF In/QF Out" methodology upon which PSD relied was one recently proposed by PSD in the consolidated standard offer proceeding. PSD states that its new approach would recognize the maturing of the QF industry and the difficulty of doing a traditional "QF In/QF Out" analysis. This difficulty, according to PSD, is due to the large number of QF's which, were they to have not been developed, would have necessitated the utility adding new resources rather than merely running the same resources differently. The new PSD "QF In/QF Out" approach therefore requires not merely removing the existing QFs for the simulation, but developing the hypothesized resource plan that would have existed if the body of QFs had not developed.[11]

(3) <u>CCC</u>

For this proceeding, the CCC endorses the use of the ELFIN model and a "QF In/QF Out" methodology for calculating avoided energy costs. The CCC notes that this methodology was adopted in the last two general rate cases involving SDG&E (D.85-12-108) and PG&E (D.86-12-091), and its use for QF pricing has been reaffirmed in D.86-07-004. Although the CCC is aware of the Commission's intention to clarify the "QF In/QF Out"

11 In performing the "QF In/QF Out" simulation, PSD removed 793 MWs of QFs and 4,715 gWh. These numbers were based on information provided by Edison as to the level of QF capacity paid on the basis of variable IERs.

It is Edison's position that the issue of whether "QF In/QF Out" should be extended to pricing for short-run standard offer QFs is an issue to be resolved in the consolidated standard offer proceeding, A.82-04-44, et al. Until that time, Edison recommends that the zero-intercept methodology continue to be used for short-run marginal cost pricing in the general rate case. Edison disputes the precedential effect of the "QF In/QF Out" methodology being adopted in recent general rate cases. Edison observes that in the San Diego Gas & Electric Company (SDG&E) general rate case, SDG&E had proposed a "QF In/QF Out" methodology. Additionally, Edison states that D.86-12-071, in which the Commission adopted such a methodology for QF pricing for Pacific Gas and Electric Company (PG&E), was specifically intended not to be precedential.[10]

With respect to model and methodological adjustments made by the other parties, Edison is critical of IEP and CCC's external adjustment to the ELFIN production cost runs to account for start-up and no-load costs. Edison notes that most (i.e., 95%) of the adjustment is related to no-load fuel costs. Edison states that such an adjustment of ELFIN results is unnecessary since the ELFIN runs already capture the no-load fuel expense by including as an input the first production block for each oil/gas unit as an average value. Edison states that the average value, as opposed to the incremental value, reflects no-load fuel expenses associated

10 If a "QF In/QF Out" methodology is adopted, Edison states that the Commission may be required to determine the quantity of QF production removed from the "QFs In" scenario in order to develop the "QFs Out" scenario. Edison believes that the CCC erred in its estimate of 76% of QF production receiving short-run standard offer energy prices and removing this amount of QF production. According to Edison, this estimate assumes that all non-standard contracts are variable priced and thereby overstates the amount of variable priced QF production.

methodology in A.82-04-044, et al., the CCC believes that until there is a change in policy, the "QF In/QF Out" methodology should be followed.

In implementing the "QF In/QF Out" methodology, the CCC included all QFs expected to be generating power in the "QF In" case. For the "QF Out" case, all QFs whose pricing is variable are removed, while those QFs with fixed prices are included. The CCC recommends that the Commission characterize 76% of QF contracts as variable priced, based on Edison's responses to data to the CCC and on the assumption that only QFs with Interim Standard Offer 4 contracts have fixed prices.

The CCC believes that it has correctly implemented the "QF In/QF Out" methodology and properly relied on the ELFIN model. The CCC notes that "[a]mong the range of possible choices, ELFIN is the most widely used publicly available production simulation model" and "utilizes a probabilistic dispatch algorithm conceptually identical to that which underlies PROMOD." (Exhibit 102, at p. 4-2 - 4-3.) Further, the CCC states that the ELFIN model has been shown to provide both reliable and accurate simulation results and is used by both the PSD and the California Energy Commission.

The CCC states that it took the initial step in using ELFIN of calibrating or matching the model with PROMOD to ensure that the two models were run with consistent empirical foundations. In the CCC's opinion, the success of its efforts were confirmed by the fact that the CCC's calibrated runs resulted in a deviation below 5% for all categories. After calibration, the CCC then changed Edison's assumptions that, in the CCC's opinion, were flawed, outmoded, or incorrect. The corrected simulations resulted in a marginal energy cost of 25.2 mills/kWh. Based on a gas cost of $2.52/MMBtu, an IER of 9,988 Btu/kWh resulted. This simulation included an adjustment for start-up and no-load costs.

with the operation of the unit at its minimum loading level. Edison notes that this level is the same as that at which specific resources are forced to remain on-line as "must-run" units, which is when the no-load fuel expense is incurred. For these reasons, it is Edison's opinion that IEP's and the CCC's separate adjustment for no-load fuel expenses double-counts these expenses.

Edison, however, does not find PSD in error in making an adjustment for no-load and start-up costs for its PCAM analysis since PSD's modeling results reflect an instantaneous marginal energy cost calculation for which such an adjustment is appropriate. Edison objects, however, to PSD's suggestion that the Commission should require further investigation of start-up and no-load fuel expenses in future proceedings since all parties adopted the results of Edison's studies and PSD's problems seemed limited to the need for additional back-up documentation. Edison is willing to provide the information, but does not feel that a mandate to conduct an additional study is warranted.

Finally, Edison responds to concerns regarding the access by other parties to PROMOD and data related to its use. Edison states that it fully complied with the statutory requirements by disclosing data bases, input and output information, and meeting with intervenors to provide them all information "to the extent necessary for cross-examination or rebuttal" (Section 1822(a)). On the subject of the timeliness of data responses, Edison cites the substantial time constraints that face all parties due to the strict schedule to which a general rate case must adhere. Edison believes that given those time constraints, Edison used its best efforts to respond fully and on a timely basis.

(2) PSD

Like Edison, PSD proposes that the Commission use the same methodology to calculate both marginal and avoided energy

Unlike PROMOD, the CCC confirms that ELFIN does not have a unit commitment capability and does not capture no-load and start-up costs. The CCC states that it compensated for the absence of these features by selecting the most likely marginal units to be "must-run" units and by making an external adjustment for no-load and start-up costs. Specifically, the CCC used time-weighted adders from Edison's historical studies to adjust its IER to capture these costs. The CCC notes that Edison does not dispute the need for a separate adjustment to the ELFIN model to account for start-up expenses.

With respect to the no-load adjustment, the CCC asks that the Commission reject Edison's assertion that this adjustment results in double-counting no-load costs. The CCC agrees with IEP that with ELFIN there may be some potential for double-counting of these costs, but that this double-counting is insignificant. Specifically, the cost effect on the $58,000,000 production cost difference between IEP's "QF In/QF Out" runs was merely $26,000 and had no effect on the ultimate IER result.

The CCC also believes that two other adjustments are required to translate the marginal energy cost and IER estimates into actual QF payments. First, in a manner consistent with the overall valuation of QF production, each of the marginal energy costs and IER estimates should be adjusted for the appropriate level of line losses and variable O&M expenses that would have been incurred by the utility but for the presence of QFs. The CCC agrees to the use of Edison's calculations of these factors. Second, each of the resulting payments should be time-differentiated to the extent that variations in marginal energy costs are expected to be significant across days, weeks, or months of the year.

In response to Edison's proposed methodology, the CCC challenges both the access provided by Edison to PROMOD as well as Edison's modeling approach. The CCC states that because Edison

costs. PSD similarly cites this Commission's decision endorsing such an approach in Edison's last general rate case (D.84-12-068).

To accomplish this goal, PSD believes that its modeling approach based on the combined use of the PCAM/IAM models was the most accurate forecasting tool presented in the proceeding. This approach involves the use of two separate input files for resources. These two files represent resources which are either "energy limited" (Edison's hydro and certain firm hydro purchases) or "capacity limited" (all steam units, combustion turbines, fossil purchases). Purchases are placed in one or the other files depending on their characteristics.

PSD believes that modeling the characteristics of virtually any resource type, including economy energy, pumped storage, and different hydro types, provides a great deal of flexibility. Units can be dispatched economically, in a predetermined order, or economically with alterations to reflect dispatch limits such as for QFs, "must run" units, and purchased power. PSD states that its model can calculate on-, mid- and off-peak marginal energy costs for up to 20 rate periods and reports IERs and unit data on all modeled resources.

PSD states that its model directly calculates the IERs and marginal costs for all costing periods. Only one adjustment is made external to the model and that is an adjustment to the on-peak incremental energy rate to reflect start-up and no-load fuel. In making its adjustment, PSD utilized a detailed study performed by Edison on the impact of start-up and no-load fuel costs using historic data. PSD believes the use of Edison's study of historic start-up and no-load fuel relationships provides the most accurate means of forecasting those costs.

With respect to the models and approaches used by the other parties, PSD notes that, unlike IAM/PCAM, the PROMOD model used by Edison does not produce a direct calculation of marginal energy costs for all costing periods. Instead, PROMOD is

regards PROMOD as propriety, Edison refuses to submit the model for assessment. In turn, the CCC asserts that independent evaluation of the validity of the models has been impossible. The CCC believes that Edison's position prevents a fair evaluation of its approach to calculating marginal costs and is in contravention of Public Utilities Code Section 1822.[12] The CCC believes that when a utility refuses to submit its computer models to independent verification, the Commission should impose stringent burdens of proof to ensure fair evaluation of all forecasts.

The CCC also criticizes Edison's failure to respond to the data requests of intervenors in a timely manner. This failure, in the CCC's opinion, severely curtailed the ability of intervenors to fully analyze Edison's showing or complete their own presentations.

With respect to Edison's proposed "zero-intercept" methodology, the CCC believes that this methodology is not consistent with the Commission's adoption of the "QF In/QF Out" methodology and has a number of flaws. Among them, the CCC believes that Edison's approach for calculating costs for the off-peak period ignores the effect of QF power on utility "no-load" and "start-up" costs. Second, the CCC asserts that the "zero-intercept" approach illustrates only the consequences of changing loads on utility operating costs. According to the CCC, this determination does not truly measure avoided costs unlike the "QF In/QF Out" methodology which calculates precisely the implications of QF production on a utility's operating costs. The CCC also

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12 Section 1822 provides generally that, to the extent necessary for cross-examination or rebuttal, the Commission and interested parties shall have access to any computer model and related data that is the basis for any testimony or exhibit in a Commission proceeding. The requirements of this statute and the status of the Commission rules governing computer access are included in our discussion on marginal energy costs.

used directly to compute only off-peak marginal costs with the "zero intercept" methodology being used to calculate on- and mid-peak marginal energy costs.

Additionally, PSD questions and considers arbitrary Edison's use of the plus and minus 500 MW variations of on-peak and mid-peak loads in developing marginal energy costs for those time period. PSD criticizes the lack of scientific basis for the use of this particular increment other than Edison's assertion that the adjustment yields more reasonable results than the adjustment is not made. PSD also notes that the plus and minus 500 MW adjustment in this case differs from Edison's last general rate case in which two alternative adjustments were used--+/- 400 MW and +/- 800 MW.

On the subject of the use of ELFIN by IEP and the CCC, PSD states that it uses ELFIN extensively for resource planning purposes and for the long-run marginal costs used in evaluating the cost-effectiveness of resource additions and demand side management proposals. It is not clear to the PSD, however, that ELFIN is capable of computing marginal energy costs for various time periods. While there are no obvious inherent problems, PSD notes that the ELFIN simulations produced consistently higher incremental energy rates than PSD or Edison without an explanation.

PSD also references ELFIN's potential for double-counting of start-up and no-load fuel. PSD notes in particular IEP's testimony that ELFIN uses average heat rates at the minimum MW level of a unit, thereby accounting for no-load costs. If the average heat rate option is used on ELFIN then an external adjustment of start-up and no-load Btus should not be made to the IER.

With respect to the calculation of avoided energy payments for QF pricing, PSD supports a "QF In" approach. In doing so, PSD points out that the "QF In" approach was the one last used for Edison. In addition, while the Commission appears to have

notes that at the time the Commission adopted the "zero-intercept" methodology in Edison's last general rate case, the "QF In/QF Out" methodology was not before the Commission.

(4) IEP

IEP similarly proposed the use of ELFIN and the "QF In/QF Out" methodology to calculate avoided energy costs for QF payments. IEP's calculations yielded an IER of 10,147 Btu/kWh. According to IEP, the Commission has determined that the "QF In/QF Out" methodology is in keeping with PURPA's requirement that the QF should be paid on the basis of those costs which the utility avoids due to the presence of QFs. It is therefore reasonable to calculate that price without including those QFs who are not in existence, but will be brought on line as a result of that price. (D.85-07-022, Finding of Fact 25.)

In IEP's view, among the short-run energy price methodologies developed to date, only "QF In/QF Out" reflects the change in total system costs caused by the QFs which will receive a price based on the utility's avoided costs. IEP believes that no persuasive reason has been shown in this proceeding not to implement "QF In/QF Out."

With respect to the adjustment for avoided start-up and no-load fuel consumption, IEP notes that Edison has chosen to rely on the interworkings of the PROMOD model to account for this consumption. IEP believes the Commission should reject this position due to Edison's own admission that PROMOD fails to calculate a value commensurate with what recorded data indicates is appropriate. While Edison proposes to include an adjustment of approximately 550 Btu/kWh, the PROMOD generated value, Edison testified that studies of recorded data show empirically that 620 Btu/kWh is the actual level of avoided start-up and no-load fuel consumption.

IEP also believes that Edison argues erroneously that double-counting will occur if the "QF In/QF Out" results from

chosen the results from a "QF In/QF Out" simulation for the most recent PG&E test year, the PSD does not believe that the Commission expressed any commitment to that method. Thus, the PSD recommends that until the Commission makes it clear as to what approach is to be utilized, consistency requires the continued use of the "QF In" method.

Recognizing the possibility of a "QF In/QF Out" approach being adopted in this proceeding, PSD, however, also offered results from using such a methodology. In performing the "QF In/QF Out" simulation, PSD removed 793 MWs of QFs and 4,715 gWh. These numbers were based on information provided by Edison as to the level of QF capacity paid on the basis of variable IERs.

(3) CCC

For this proceeding, the CCC endorses the use of the ELFIN model and a "QF In/QF Out" methodology for calculating avoided energy costs. The CCC notes that this methodology was adopted in the last two general rate cases involving SDG&E (D.85-12-108) and PG&E (D.86-12-091), and its use for QF pricing has been reaffirmed in D.86-07-004. Although the CCC is aware of the Commission's intention to clarify the "QF In/QF Out" methodology in A.82-04-44, et al., the CCC believes that until there is a change in policy, the "QF In/QF Out" methodology should be followed.

In implementing the "QF In/QF Out" methodology, the CCC included all QFs expected to be generating power in the "QF In" case. For the "QF Out" case, all QFs whose pricing is variable are removed, while those QFs with fixed prices are included. The CCC recommends that the Commission characterize 76% of QF contracts as variable priced, based on Edison's responses to data to the CCC and on the assumption that only QFs with Interim Standard Offer 4 contracts have fixed prices.

The CCC believes that it has correctly implemented the "QF In/QF Out" methodology and properly relied on the ELFIN

ELFIN are adjusted. IEP states ELFIN does not estimate plant start-ups, as PROMOD attempts to do, and does not have the ability to account for plant fuel consumption at levels below minimum generating levels (i.e., no-load fuel consumption). Since neither of these phenomenon is accounted for in ELFIN, IEP argues that it is entirely appropriate and necessary to make the type of external adjustment to the IER recommended by IEP to account for start-up and no-load fuel costs.

(5) CSC

The CSC expressly adopts the positions and argument articulated by the CCC in this proceeding. Like the CCC, the CSC takes exception to Edison's failure to timely respond to the data requests of the interested parties. Additionally, the CSC endorses the use of the ELFIN model using a "QF In/QF Out" methodology. The CSC also endorses IEP's and CCC's adjustment to the ELFIN modeling results for start-up and no-load costs of about 620 Btu/kWh.

b. Input Assumptions

In addition to the type of computer model and specific methodology chosen, equally critical to the calculation of the IER are the assumptions which each party used in performing their respective production cost model simulations. In this proceeding, the vast majority of input values was used in common by all parties and was based on Edison data.

Nevertheless, certain critical assumptions were the subject of debate between the parties. The resource assumptions at issue in this proceeding fall into the following basic categories: (1) base load unit production (nuclear and coal units), (2) economy energy availability and purchases, (3) firm power (capacity and energy) purchases, and (4) QF generation. Differences also exist between the parties regarding the assumptions used for the price of natural gas and minimum load conditions. Concern in this proceeding was also expressed regarding the manner in which IERs model. The CCC notes that "[a]mong the range of possible choices, ELFIN is the most widely used publicly available production simulation model" and "utilizes a probabilistic dispatch algorithm conceptually identical to that which underlies PROMOD." (Exhibit 102, at p. 4-2 - 4-3.) Further, the CCC states that the ELFIN model has been shown to provide both reliable and accurate simulation results and is used by both the PSD and the California Energy Commission.

The CCC states that it took the initial step in using ELFIN of calibrating or matching the model with PROMOD to ensure that the two models were run with consistent empirical foundations. In the CCC's opinion, the success of its efforts were confirmed by the fact that the CCC's calibrated runs resulted in a deviation below 5% for all categories. After calibration, the CCC then changed Edison's assumptions that, in the CCC's opinion, were flawed, outmoded, or incorrect. The corrected simulations resulted in a marginal energy cost of 25.2 mills/kWh. Based on a gas cost of $2.52/MMBtu, an IER of 9,988 Btu/kWh resulted. This simulation included an adjustment for start-up and no-load costs.

Unlike PROMOD, the CCC confirms that ELFIN does not have a unit commitment capability and does not capture no-load and start-up costs. The CCC states that it compensated for the absence of these features by selecting the most likely marginal units to be "must-run" units and by making an external adjustment for no-load and start-up costs. Specifically, the CCC used time-weighted adders from Edison's historical studies to adjust its IER to capture these costs. The CCC notes that Edison does not dispute the need for a separate adjustment to the ELFIN model to account for start-up expenses.

With respect to the no-load adjustment, the CCC asks that the Commission reject Edison's assertion that this adjustment results in double-counting no-load costs. The CCC agrees with IEP that with ELFIN there may be some potential for double-counting of should be adjusted to reflect the Commission's adopted input assumptions and the need for an annual update of the IER.

(1) Base Load Unit Production Asumptions

For coal units, Edison proposes that an annual long-range capacity of 62% be used. In support of this assumption, Edison cites the adoption by the California Energy Commission of a 63% capacity factor for Edison's coal units in its ER-VI, January, 1987, Report.

For its nuclear units, Edison proposes an annual long-range capacity factor of 65% for Edison's mature nuclear units. Edison believes that its recommended value is based on the most current information regarding the maintenance schedules of such units. Edison also supports its assumption of a full-year operation of its Palo Verde 3 unit based on the reasonable assumption of a considerable amount of pre-release energy generation in January and February of 1988.

The CCC challenges Edison's proposed capacity factors for both its coal and nuclear units. The CCC asserts that in making its forecast of generation from its coal plants, Edison failed to use historical averages, as the CCC believes the Commission requires (see D.86-07-004), and failed to account for major outage factors. The CCC, along with the PSD, base capacity forecast for each plant on actual performance over the past five years, resulting in an average of a 63% capacity factor.

With respect to Edison's forecast of nuclear power generation, the CCC notes that the Commission has determined that forecasts of the performance of thermal units should be based on a rolling historical five-year average for each specific plant. Alternatively, if five years of operating data are not available, the Commission prescribes use of a national average of similar units. (See D.86-07-004, at p. 86.) Since only San Onofre Nuclear Generating Station (SONGS) 1 of Edison's six nuclear units included in Edison's weighted average capacity factor is older than five these costs, but that this double-counting is insignificant. Specifically, the cost effect on the $58,000,000 production cost difference between IEP's "QF In/QF Out" runs was merely $26,000 and had no effect on the ultimate IER result.

The CCC also believes that two other adjustments are required to translate the marginal energy cost and IER estimates into actual QF payments. First, in a manner consistent with the overall valuation of QF production, each of the marginal energy costs and IER estimates should be adjusted for the appropriate level of line losses and variable O&M expenses that would have been incurred by the utility but for the presence of QFs. The CCC agrees to the use of Edison's calculations of these factors. Second, each of the resulting payments should be time-differentiated to the extent that variations in marginal energy costs are expected to be significant across days, weeks, or months of the year.

In response to Edison's proposed methodology, the CCC challenges both the access provided by Edison to PROMOD as well as Edison's modeling approach. The CCC states that because Edison regards PROMOD as propriety, Edison refuses to submit the model for assessment. In turn, the CCC asserts that independent evaluation of the validity of the models has been impossible. The CCC believes that Edison's position prevents a fair evaluation of its approach to calculating marginal costs and is in contravention of Public Utilities Code Section 1822.[11] The CCC believes that when a utility refuses to submit its computer models to independent

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11 Section 1822 provides generally that. to the extent necessary for cross-examination or rebuttal, the Commission and interested parties shall have access to any computer model and related data that is the basis for any testimony or exhibit in a Commission proceeding. The requirements of this statute and the status of the Commission rules governing computer access are included in our discussion on marginal energy costs.

years, the national average should be used to forecast performance of all of Edison's other plants.

Under these criteria, SONGS 1 would be modeled with its five-year historical capacity factor of 53%. In contrast, Edison proposes to adjust the historical average for SONGS 1 to diminish the effect of the shutdown that occurred during the five-year period, thus proposing a capacity factor of 57%. The CCC calls this approach unacceptable when the point of the historical average is to use the actual performance of a particular unit, whether poor, average or exceptional, to predict performance for the forecast period.

With respect to the remaining units with less than five years of operating data, the CCC testified that the national average performance of units with capacities in excess of 700 MW ranges from 37% to 86%. However, the mean performance of all units averages between 58% and 60%. The CCC recommends that the Commission adopt 59% as the appropriate capacity factor for these units.

The CCC and the CSC also question Edison's proposed capacity factor of 75% for Palo Verde 3 based on an operating date of November, 1987. The CCC points out that evidence in Edison's ECAC reflects that this date has slipped to no earlier than March 1, 1988. The CCC asks that the Commission assume March 1, 1988 for the commercial operating date for the Palo Verde 3 unit.

(2) Economy Energy Purchases

Each of the parties presented different assumptions regarding the amount of economy energy available and expected to be purchased by Edison from both the Pacific Northwest (PNW) and Pacific Southwest (PSW) regions. The differences were primarily due to the use of differing estimation techniques.

It is Edison's position that because Edison alone forecasted economy energy availability based on detailed computer model simulations of the geographical regions, more analytical verification, the Commission should impose stringent burdens of proof to ensure fair evaluation of all forecasts.

The CCC also criticizes Edison's failure to respond to the data requests of intervenors in a timely manner. This failure, in the CCC's opinion, severely curtailed the ability of intervenors to fully analyze Edison's showing or complete their own presentations.

With respect to Edison's proposed "zero-intercept" methodology, the CCC believes that this methodology is not consistent with the Commission's adoption of the "QF In/QF Out" methodology and has a number of flaws. Among them, the CCC believes that Edison's approach for calculating costs for the off-peak period ignores the effect of QF power on utility "no-load" and "start-up" costs. Second, the CCC asserts that the "zero-intercept" approach illustrates only the consequences of changing loads on utility operating costs. According to the CCC, this determination does not truly measure avoided costs unlike the "QF In/QF Out" methodology which calculates precisely the implications of QF production on a utility's operating costs. The CCC also notes that at the time the Commission adopted the "zero-intercept" methodology in Edison's last general rate case, the "QF In/QF Out" methodology was not before the Commission.

(4) <u>IEP</u>

IEP similarly proposed the use of ELFIN and the "QF In/QF Out" methodology to calculate avoided energy costs for QF payments. IEP's calculations yielded an IER of 10,147 Btu/kWh. According to IEP, the Commission has determined that the "QF In/QF Out" methodology is in keeping with PURPA's requirement that the QF should be paid on the basis of those costs which the utility avoids due to the presence of QFs. It is therefore reasonable to calculate that price without including those QFs who are not in existence, but will be brought on line as a result of that price. (D.85-07-022, Finding of Fact 25.)

weight must be afforded to Edison's assumptions. Edison believes that reliance on expert judgment and historical analysis is not a substitute for the type of extensive analysis of the specific regional resources and loads which it undertook. Edison also notes that reliance on estimates proposed in ECAC is misplaced since the ECAC estimate is for the amount of economy energy expected to be purchased, not the total that was assumed available. Edison asserts that availability, and not price, should be the criteria for determining economy energy purchases.

Edison's revised estimate of economy energy available for the PNW for 1988 was 5,072 gWh.[13] Edison's final estimate of PSW economy energy for 1988 was 7,642 gWh (Table 2, Exhibit 109).

PSD, in developing its estimates of PNW and PSW economy energy availability, used, as a base number, the full year recorded figures for Edison receipt of non-firm energy from December 1985 through November 1986. For this time period, the results were 7,509 gWh for the PNW and 3,199 gWh for the PSW. By 1990, PSD is forecasting a decrease on an annual basis to 652 gWh for the PNW region and 735 gWh for the PSW region, a total of 1,387 gWh. These estimates were based on PSD's resource plan "bridging the gap" between the 1986 recorded figures and the 1990 forecast, with an equal percent reduction in each year.

13 Edison's original estimate of economy energy purchases from the PNW region was 5,380 gWh. This estimate was revised in Edison's rebuttal testimony (Exhibit 109) to reflect (1) a reduction in the portion of the Wyodak Coal Plant output available for surplus energy production; and (2) the use of more recent forecasts for the Eastern Montana and Wyoming loads. Edison estimated that the effect of these changes in the PNW model would be to reduce Edison's estimate by about 308 gWh of energy availability. Both factors resulting in the total reduction of 308 gWh are attributable to economy energy purchases.

In IEP's view, among the short-run energy price methodologies developed to date, only "QF In/QF Out" reflects the change in total system costs caused by the QFs which will receive a price based on the utility's avoided costs. IEP believes that no persuasive reason has been shown in this proceeding not to implement "QF In/QF Out."

With respect to the adjustment for avoided start-up and no-load fuel consumption, IEP notes that Edison has chosen to rely on the interworkings of the PROMOD model to account for this consumption. IEP believes the Commission should reject this position due to Edison's own admission that PROMOD fails to calculate a value commensurate with what recorded data indicates is appropriate. While Edison proposes to include an adjustment of approximately 550 Btu/kWh, the PROMOD generated value, Edison testified that studies of recorded data show empirically that 620 Btu/kWh is the actual level of avoided start-up and no-load fuel consumption.

IEP also believes that Edison argues erroneously that double-counting will occur if the "QF In/QF Out" results from ELFIN are adjusted. IEP states ELFIN does not estimate plant start-ups, as PROMOD attempts to do, and does not have the ability to account for plant fuel consumption at levels below minimum generating levels (i.e., no-load fuel consumption). Since neither of these phenomenon is accounted for in ELFIN, IEP argues that it is entirely appropriate and necessary to make the type of external adjustment to the IER recommended by IEP to account for start-up and no-load fuel costs.

(5) <u>CSC</u>

The CSC expressly adopts the positions and argument articulated by the CCC in this proceeding. Like the CCC, the CSC takes exception to Edison's failure to timely respond to the data requests of the interested parties. Additionally, the CSC endorses the use of the ELFIN model using a "QF In/QF Out" methodology. The

PSD acknowledges that its forecasts for economy energy are dramatically lower than Edison's and the various interested parties. PSD also notes the variation between these estimates and those presented by PSD in Edison's current ECAC proceeding.

PSD states, however, that reasons exist for the differences in these estimates. Specifically, PSD notes that in ECAC PSD uses short-term forecasts that have close relationships with the recorded usage in the immediate past and are intended to be applicable only to the immediate forecast period. The rate case forecasts, by definition, have to be more in tune with average year forecasts being applicable to the test year and attrition year. PSD notes further that Edison's own forecasts differed between this proceeding and ECAC despite Edison's indication that the forecast period results for the two proceedings should be similar.

PSD also believes that its estimates take into account the recent history of PNW transactions with California. This history, in PSD's view, demonstrates that physical capability does not equate to availability.

Finally, PSD asserts that Edison's models for PNW and PSW economy energy are flawed for failing to consider the most critical element necessary in evaluating the availability of the resource--price. While Edison's PROMOD runs include a price computation for non-firm energy of 60% of the average cost of gas, PSD believes that this ratio is too low noting PSD's own assumption of the PNW non-firm price being 85% of the Edison avoided energy price.[14]

IEP, the CSC, and the CCC all challenge Edison's estimates of economy energy purchases. IEP estimates that 5,557

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14 PSD states that its estimate is consistent with current price behavior under the Bonneville Power Administration (BPA) Intertie Access Policy.

CSC also endorses IEP's and CCC's adjustment to the ELFIN modeling results for start-up and no-load costs of about 620 Btu/kWh.

b. Input Assumptions

In addition to the type of computer model and specific methodology chosen, equally critical to the calculation of the IER are the assumptions which each party used in performing their respective production cost model simulations. In this proceeding, the vast majority of input values was used in common by all parties and was based on Edison data.

Nevertheless, certain critical assumptions were the subject of debate between the parties. The resource assumptions at issue in this proceeding fall into the following basic categories: (1) base load unit production (nuclear and coal units), (2) economy energy availability and purchases, (3) firm power (capacity and energy) purchases, and (4) QF generation. Differences also exist between the parties regarding the assumptions used for the price of natural gas and minimum load conditions. Concern in this proceeding was also expressed regarding the manner in which IERs should be adjusted to reflect the Commission's adopted input assumptions and the need for an annual update of the IER.

(1) Base Load Unit Production Asumptions

For coal units, Edison proposes that an annual long-range capacity of 62% be used. In support of this assumption, Edison cites the adoption by the California Energy Commission of a 63% capacity factor for Edison's coal units in its ER-VI, January, 1987, Report.

For its nuclear units, Edison proposes an annual long-range capacity factor of 65% for Edison's mature nuclear units. Edison believes that its recommended value is based on the most current information regarding the maintenance schedules of such units. Edison also supports its assumption of a full-year operation of its Palo Verde 3 unit based on the reasonable gWh of economy energy purchases will be made from the PNW region for 1988. IEP states that this estimate which is 190 gWh less than Edison has estimated for the ECAC period reflects the price/quantity relationship, which affects economy energy purchase decisions. The expected level of economy energy purchases is affected by Edison's decision to dispatch its system based on the incremental or spot price of gas.

IEP's estimates for the test year are very similar to those made by Edison for the June 1987 through May 1988 ECAC period. IEP recognizes that these periods are not identical, but notes, as did PSD, that in this proceeding Edison testified that there was no reason to believe that the expectations of purchases would differ between these overlapping periods.

The CSC also believes that Edison's modeling of PNW energy availability is flawed. The CSC states that both conceptual and mathematical errors in Edison's model have resulted in substantial overstatements of both the availability of PNW energy (by 1,876 gWh) and the actual purchases of PNW energy (by 2,690 gWh). The CSC believes that these errors include (1) Edison having understated the PNW region's load and the Eastern Montana-Wyoming load and overstated resource availability by ignoring resource generation cost and ownership and (2) ignoring the physical capability of the transmission system resulting in purchases exceeding the intertie capability for over 3,300 hours.

The CSC's approach in estimating PNW energy availability was to use instead only the Northwest Regional Forecast which the CSC believes provided a consistent set of forecast assumptions in a single publication. The CCC endorses the CSC's position and results.

With respect to the PSW model and assumptions, the CCC notes that Edison assumed that in 1988 it would purchase 7,642 gWh of non-firm energy from the Inland Southwest at a cost of 22.4 mills/kWh in on-peak periods and 16.4 mills/kWh in the off-peak assumption of a considerable amount of pre-release energy generation in January and February of 1988.

The CCC challenges Edison's proposed capacity factors for both its coal and nuclear units. The CCC asserts that in making its forecast of generation from its coal plants, Edison failed to use historical averages, as the CCC believes the Commission requires (see D.86-07-004), and failed to account for major outage factors. The CCC, along with the PSD, base capacity forecast for each plant on actual performance over the past five years, resulting in an average of a 63% capacity factor.

With respect to Edison's forecast of nuclear power generation, the CCC notes that the Commission has determined that forecasts of the performance of thermal units should be based on a rolling historical five-year average for each specific plant. Alternatively, if five years of operating data are not available, the Commission prescribes use of a national average of similar units. (See D.86-07-004, at p. 86.) Since only San Onofre Nuclear Generating Station (SONGS) 1 of Edison's six nuclear units included in Edison's weighted average capacity factor is older than five years, the national average should be used to forecast performance of all of Edison's other plants.

Under these criteria, SONGS 1 would be modeled with its five-year historical capacity factor of 53%. In contrast, Edison proposes to adjust the historical average for SONGS 1 to diminish the effect of the shutdown that occurred during the five-year period, thus proposing a capacity factor of 57%. The CCC calls this approach unacceptable when the point of the historical average is to use the actual performance of a particular unit, whether poor, average or exceptional, to predict performance for the forecast period.

With respect to the remaining units with less than five years of operating data, the CCC testified that the national average performance of units with capacities in excess of 700 MW periods. The CCC finds these projections flawed for two reasons. First, CCC aserts that, as noted by PSD, Edison's out-of-state economy energy projections were as much as 22% higher than recently recorded levels. Second, the CCC states that for its updated ECAC filing, Edison's expected value for Inland Southwest economy energy had fallen to 4,398 gWh, with an average price of only 14 mills/kWh. The CCC notes that the more current ECAC forecast accounts for the historical 1986 recorded prices, the two-tiered GN-5 rate, and operational considerations. The CCC therefore recommends the adoption of Edison's ECAC energy forecast for the Inland Southwest.

(3) Firm Power Purchases

In this proceeding, the issue arose as to whether or not three purchase power contracts were properly considered by Edison to be firm commitments. The three agreements at issue include: (1) the BPA Memorandum of Understanding (MOU), (2) the Pacific Power & Light Company (PP&L) Memorandum of Agreement, and (3) the Portland General Electric Company (PGE) contract.

Edison states that it has consistently held the position that all three of the contracts are committed resources. Since the close of hearings in this proceeding, Edison has advised the Commission that a definitive contract has now been executed between Edison and PP&L and filed with the Federal Energy Regulatory Commission (FERC) on July 1, 1987 in FERC Docket No. ER 87-521-000. Edison requests the Commission to take official notice of this filing.

With respect to the PGE contract, Edison states that the parties seek to exclude this agreement on the basis that purchases under the contract would be too expensive. Edison states that the economics of the contract are not at issue in this proceeding, that the agreement represents a legally binding commitment which Edison has made, and that exclusion of the ranges from 37% to 86%. However, the mean performance of all units averages between 58% and 60%. The CCC recommends that the Commission adopt 59% as the appropriate capacity factor for these units.

The CCC and the CSC also question Edison's proposed capacity factor of 75% for Palo Verde 3 based on an operating date of November, 1987. The CCC points out that evidence in Edison's ECAC reflects that this date has slipped to no earlier than March 1, 1988. The CCC asks that the Commission assume March 1, 1988 for the commercial operating date for the Palo Verde 3 unit.

(2) Economy Energy Purchases

Each of the parties presented different assumptions regarding the amount of economy energy available and expected to be purchased by Edison from both the Pacific Northwest (PNW) and Pacific Southwest (PSW) regions. The differences were primarily due to the use of differing estimation techniques.

It is Edison's position that because Edison alone forecasted economy energy availability based on detailed computer model simulations of the geographical regions, more analytical weight must be afforded to Edison's assumptions. Edison believes that reliance on expert judgment and historical analysis is not a substitute for the type of extensive analysis of the specific regional resources and loads which it undertook. Edison also notes that reliance on estimates proposed in ECAC is misplaced since the ECAC estimate is for the amount of economy energy expected to be purchased, not the total that was assumed available. Edison asserts that availability, and not price, should be the criteria for determining economy energy purchases.

contract would result in payments to QFs for duplicate capacity which Edison is already committed to purchase.

The BPA contract is, in Edison's view, an extension of the existing contract between the two parties. According to Edison, the contract, which is scheduled for termination in the summer of 1987, has been the subject of negotiations for the last two years. While the original MOU was removed due to the unfavorable economics perceived by Edison, Edison still expects to have a contract in effect by October, 1987. Edison believes that the resources should be considered committed until it is clear that a new similarly advantageous contract cannot be negotiated. In Edison's view, a finding that the arrangement will not continue causes the ratepayers to lose an opportunity to reap the benefits that have and will continue to exist in the PNW region.

In its testimony, PSD indicated its reservations regarding these contracts by excluding from its assumptions of firm purchase power all but the BPA agreement, the certainty of which PSD also questioned. PSD states that these agreements have not received all of the requisite approvals necessary to allow them to go into effect. PSD also believes that urgency in negotiating these agreements has been minimized by the adoption of the Intertie Access Policy by BPA and the presence of excess capacity on the Edison system, a circumstance which is expected to exist well into the next decade. At this time, the PSD believes that the inclusion of any of these agreements in marginal cost calculations should be done with extreme caution.

The CSC also challenged inclusion of the three agreements, but with respect to Edison's calculation of its Energy Reliability Index (ERI) calculation used in developing avoided capacity costs. To ensure consistency in our findings regarding the status of these agreements, we note the CSC's objections here as well.

Edison's revised estimate of economy energy available for the PNW for 1988 was 5,072 gWh.[12] Edison's final estimate of PSW economy energy for 1988 was 7,642 gWh (Table 2, Exhibit 109).

PSD, in developing its estimates of PNW and PSW economy energy availability, used, as a base number, the full year recorded figures for Edison receipt of non-firm energy from December 1985 through November 1986. For this time period, the results were 7,509 gWh for the PNW and 3,199 gWh for the PSW. By 1990, PSD is forecasting a decrease on an annual basis to 652 gWh for the PNW region and 735 gWh for the PSW region, a total of 1,387 gWh. These estimates were based on PSD's resource plan "bridging the gap" between the 1986 recorded figures and the 1990 forecast, with an equal percent reduction in each year.

PSD acknowledges that its forecasts for economy energy are dramatically lower than Edison's and the various interested parties. PSD also notes the variation between these estimates and those presented by PSD in Edison's current ECAC proceeding.

PSD states, however, that reasons exist for the differences in these estimates. Specifically, PSD notes that in ECAC PSD uses short-term forecasts that have close relationships with the recorded usage in the immediate past and are intended to be applicable only to the immediate forecast period. The rate case

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12 Edison's original estimate of economy energy purchases from the PNW region was 5,380 gWh. This estimate was revised in Edison's rebuttal testimony (Exhibit 109) to reflect (1) a reduction in the portion of the Wyodak Coal Plant output available for surplus energy production; and (2) the use of more recent forecasts for the Eastern Montana and Wyoming loads. Edison estimated that the effect of these changes in the PNW model would be to reduce Edison's estimate by about 308 gWh of energy availability. Both factors resulting in the total reduction of 308 gWh are attributable to economy energy purchases.

Specifically, the CSC notes that no definitive agreement, memorandum, arrangement, or contract of any kind exists between Edison and BPA. Further, Edison has admitted to the 259 MW MOU with BPA being "off-the-table." The CSC believes that the PP&L agreement is even less committed since it had not been made available for review at the time of the hearings. Finally, the CSC notes that the PGE contract is still subject to regulatory review by FERC and contains express provisions calling for a recision or reformation of the contract in the event of a material change caused by the regulatory approval process. The CSC also questions the price negotiated under the agreement since it is higher than the BPA MOU.

(4) <u>QF Generation</u>

During hearings in this proceeding, the CCC, IEP, and the CSC all challenged Edison's original forecast of 1988 QF generation. According to the CCC, an artificially high QF forecast produces lower IERs and ultimately results in underpayments to QFs.

The CCC states that Edison's short-term forecasts of expected QF generation demonstrate the uncertainty with this type of forecasting and underscore a pattern of needing to reduce forecasts to account for lower levels of actual QF generation. Specifically, Edison's forecast has ranged from a high of 14,362 gWh in its CFM-VI filing and 14,174 gWh in its 1986 Resource Plan to a low of 7,786 gWh in its April ECAC update. The CCC recommends that the Commission adopt Edison's April 8, 1987 forecast of 12,694 gWh, reflecting a number of QF start-up delays. This updated 1988 estimate is the most current forecast contained in the record and therefore the best estimate provided to the Commission.

IEP has estimated that QFs will produce 9,192 gWh for sale to Edison in 1988, of which 2,420 gWh will be paid for based on floating or variable energy prices. IEP believes these estimates are reasonable and should be adopted for two reasons. First, IEP's analysis was based on information provided by Edison forecasts, by definition, have to be more in tune with average year forecasts being applicable to the test year and attrition year. PSD notes further that Edison's own forecasts differed between this proceeding and ECAC despite Edison's indication that the forecast period results for the two proceedings should be similar.

PSD also believes that its estimates take into account the recent history of PNW transactions with California. This history, in PSD's view, demonstrates that physical capability does not equate to availability.

Finally, PSD asserts that Edison's models for PNW and PSW economy energy are flawed for failing to consider the most critical element necessary in evaluating the availability of the resource--price. While Edison's PROMOD runs include a price computation for non-firm energy of 60% of the average cost of gas, PSD believes that this ratio is too low noting PSD's own assumption of the PNW non-firm price being 85% of the Edison avoided energy price.[13]

IEP, the CSC, and the CCC all challenge Edison's estimates of economy energy purchases. IEP estimates that 5,557 gWh of economy energy purchases will be made from the PNW region for 1988. IEP states that this estimate which is 190 gWh less than Edison has estimated for the ECAC period reflects the price/quantity relationship, which affects economy energy purchase decisions. The expected level of economy energy purchases is affected by Edison's decision to dispatch its system based on the incremental or spot price of gas.

IEP's estimates for the test year are very similar to those made by Edison for the June 1987 through May 1988 ECAC period. IEP recognizes that these periods are not identical, but

13 PSD states that its estimate is consistent with current price behavior under the Bonneville Power Administration (BPA) Intertie Access Policy.

and a review of Edison's initial and updated forecast reports filed in their 1987 ECAC (A.87-02-019). Second, like the CCC, PEP notes the continual updating by Edison reducing its original forecast to match more current, recorded information.

In Edison's rebuttal testimony (Exhibit 109), Edison concurs that subsequent to the development of Edison's PROMOD simulations in the fall of 1986, changes had occurred in the schedules of some of the QF resources that were expected to start operation in 1988. These changes were reflected in the latest Edison ECAC update, but were not included in the Edison's general rate case filing. Edison therefore revised its original estimate of 14,174 gWh of QF generation for 1988 to reflect the more current information by reducing that figure by 1480 gWh. The result was Edison's acceptance of the CCC's estimate of 12,694 gWh.

(5) Price of Natural Gas

The price of natural gas is a particularly critical input assumption. It is the primary fuel used in Edison's own oil/gas generation and is, therefore, the incremental or marginal/avoided fuel. Differences between Edison, PSD, and the interested parties include both the prices assumed for the gas and the manner in which gas prices are modeled.

In determining the price of natural gas, Edison used a fuel cost of \$2.94/MMBtu, which is Edison's forecasted weighted average price for gas during the test year. Edison recommends, however, that the Commission adopt the most current average price. Although Edison also forecasted an incremental cost of gas (\$2.15/MMBtu), the weighted average was the only price used in its marginal energy cost calculations.

PSD used both a forecasted average price of gas at \$2.52/MMBtu and a "commodity" or "dispatch" price, also called the Tier II price, of \$1.996/MMBtu or 79% of the average price. It is the PSD view that while in the long term the price of gas will track the price of oil, in the near term, the existing gas notes, as did PSD, that in this proceeding Edison testified that there was no reason to believe that the expectations of purchases would differ between these overlapping periods.

The CSC also believes that Edison's modeling of PNW energy availability is flawed. The CSC states that both conceptual and mathematical errors in Edison's model have resulted in substantial overstatements of both the availability of PNW energy (by 1,876 gWh) and the actual purchases of PNW energy (by 2,690 gWh). The CSC believes that these errors include (1) Edison having understated the PNW region's load and the Eastern Montana-Wyoming load and overstated resource availability by ignoring resource generation cost and ownership and (2) ignoring the physical capability of the transmission system resulting in purchases exceeding the intertie capability for over 3,300 hours.

The CSC's approach in estimating PNW energy availability was to use instead only the Northwest Regional Forecast which the CSC believes provided a consistent set of forecast assumptions in a single publication. The CCC endorses the CSC's position and results.

With respect to the PSW model and assumptions, the CCC notes that Edison assumed that in 1988 it would purchase 7,642 gWh of non-firm energy from the Inland Southwest at a cost of 22.4 mills/kWh in on-peak periods and 16.4 mills/kWh in the off-peak periods. The CCC finds these projections flawed for two reasons. First, CCC aserts that, as noted by PSD, Edison's out-of-state economy energy projections were as much as 22% higher than recently recorded levels. Second, the CCC states that for its updated ECAC filing, Edison's expected value for Inland Southwest economy energy had fallen to 4,398 gWh, with an average price of only 14 mills/kWh. The CCC notes that the more current ECAC forecast accounts for the historical 1986 recorded prices, the two-tiered GN-5 rate, and operational considerations. The CCC therefore competition, combined with the restructuring of the gas industry, is expected to price gas at a discount to oil. Therefore PSD's forecasted price of natural gas is 95% of its forecasted price of Low Sulphur Waxy Residual Oil (LSWR).

The CCC endorses the 1988 gas price forecast presented by PSD of $2.52/MMBtu based on PSD price and dispatch assessments. The CCC, however, challenges the accuracy of the many and varied gas price forecasts which Edison has presented in its general rate case and ECAC applications. The CCC specifically cites four different gas price forecasts which Edison has offered: An overall gas price of $2.94/MMBtu for the original GRC application, an ECAC forecast of $2.68/MMBtu for the first five months of 1988, a revised ECAC forecast of $2.90/MMBtu, and a $2.70/MMBtu for all of 1988 used in its PROMOD simulation.

Like Edison, IEP used a weighted average gas price in its production cost analysis. PSD points out, however, that the ELFIN model used by IEP does not permit the use of a fuel dispatch price.

Edison takes issue with the use by PSD and the CCC of a Tier II price of gas for the purpose of model dispatch. Since the Commission is now paying QFs using short-run marginal costs of energy that reflect the weighted average price Edison pays for gas rather than the Tier II price, developing IERs based on models which dispatch at the Tier II price of gas would be incorrect. In reply to Edison's challenge to PSD's use of Tier II prices, PSD states that PSD's IAM model has the capability to dispatch units based on the spot price of gas. After fixing the dispatch order, however, PSD notes that the actual weighted average price of gas can then be input into the model for the purpose of marginal cost and IER calculation, a step which PSD took. In PSD's view, this modeling approach in fact most accurately reflects reality since the utility dispatchers never dispatch units based on the average recommends the adoption of Edison's ECAC energy forecast for the Inland Southwest.

(3) Firm Power Purchases

In this proceeding, the issue arose as to whether or not three purchase power contracts were properly considered by Edison to be firm commitments. The three agreements at issue include: (1) the BPA Memorandum of Understanding (MOU), (2) the Pacific Power & Light Company (PP&L) Memorandum of Agreement, and (3) the Portland General Electric Company (PGE) contract.

Edison states that it has consistently held the position that all three of the contracts are committed resources. Since the close of hearings in this proceeding, Edison has advised the Commission that a definitive contract has now been executed between Edison and PP&L and filed with the Federal Energy Regulatory Commission (FERC) on July 1, 1987 in FERC Docket No. ER 87-521-000. Edison requests the Commission to take official notice of this filing.

With respect to the PGE contract, Edison states that the parties seek to exclude this agreement on the basis that purchases under the contract would be too expensive. Edison states that the economics of the contract are not at issue in this proceeding, that the agreement represents a legally binding commitment which Edison has made, and that exclusion of the contract would result in payments to QFs for duplicate capacity which Edison is already committed to purchase.

The BPA contract is, in Edison's view, an extension of the existing contract between the two parties. According to Edison, the contract, which is scheduled for termination in the summer of 1987, has been the subject of negotiations for the last two years. While the original MOU was removed due to the unfavorable economics perceived by Edison, Edison still expects to have a contract in effect by October, 1987. Edison believes that the resources should be considered committed until it is clear that price of gas. PSD further notes that it correctly modeled QF payments on the basis of the average price of gas.

(6) Minimum Load Conditions

Minimum load conditions can be defined as the point where oil and gas fired power plants either have been turned off or are being operated at their minimum level to meet system security needs or operational constraints. During minimum load conditions, low-cost purchased power may be rejected. To the extent that Edison is required by contract to purchase higher cost power during minimum load conditions, a portion of the potential cost savings is not realized.

Edison states that in an attempt to calculate the anticipated minimum load conditions Edison used a simple regression analysis methodology. Edison acknowledges that this approach would not necessarily produce an exactly correct estimate of the minimum load hours. However, the regression did show that the expected minimum load hours would increase over time and probably be at a maximum in the 1989 to 1991 time frame. Since the only major resource additions to the Edison resource plan in the next two to three years are QF resources, the correlation of increasing minimum load conditions due to QF resource additions, as Edison did, is justifiable.

The CCC objects to Edison's methodology for the following reasons: (1) Edison failed to validate its forecasts of rejected economy energy; (2) the assumptions contained in Edison's resource plans are incorrect due to erroneously high forecasts of the availability of economy energy, QF generation, and nuclear and coal generation are too high; (3) the simulations of the Edison system do not accurately reflect the operational flexibility of the system failing to account for several factors that would reduce "must run" constraints; and (4) Edison has provided no proof that its regression equation is valid. According to the CCC, it is unlikely that a simple regression over the years can be meaningful, a new similarly advantageous contract cannot be negotiated. In Edison's view, a finding that the arrangement will not continue causes the ratepayers to lose an opportunity to reap the benefits that have and will continue to exist in the PNW region.

In its testimony, PSD indicated its reservations regarding these contracts by excluding from its assumptions of firm purchase power all but the BPA agreement, the certainty of which PSD also questioned. PSD states that these agreements have not received all of the requisite approvals necessary to allow them to go into effect. PSD also believes that urgency in negotiating these agreements has been minimized by the adoption of the Intertie Access Policy by BPA and the presence of excess capacity on the Edison system, a circumstance which is expected to exist well into the next decade. At this time, the PSD believes that the inclusion of any of these agreements in marginal cost calculations should be done with extreme caution.

The CSC also challenged inclusion of the three agreements, but with respect to Edison's calculation of its Energy Reliability Index (ERI) calculation used in developing avoided capacity costs. To ensure consistency in our findings regarding the status of these agreements, we note the CSC's objections here as well.

Specifically, the CSC notes that no definitive agreement, memorandum, arrangement, or contract of any kind exists between Edison and BPA. Further, Edison has admitted to the 259 MW MOU with BPA being "off-the-table." The CSC believes that the PP&L agreement is even less committed since it had not been made available for review at the time of the hearings. Finally, the CSC notes that the PGE contract is still subject to regulatory review by FERC and contains express provisions calling for a recision or reformation of the contract in the event of a material change caused by the regulatory approval process. The CSC also questions particularly in light of the fact that the addition of SONGS 2 and 3, the Palo Verde units, and the Intermountain Power Plant Units present highly significant perturbations to the Edison system.

The CCC also refutes Edison's assertion that QFs cause minimum load conditions. Due to additions of a substantial amount of base load capacity to the Edison system in recent years and levels of new coal and nuclear resources, the CCC contends that Edison is precluded from attributing minimum load conditions to any single generation resource.

(7) Miscellaneous Input Assumptions

In its brief Edison expressed concerns about four additional modeling or input differences: (1) heat rate input, (2) load shape data, (3) unit commitment and dispatch, and (4) choice of resource plan. Beginning with heat rate input, Edison expresses concern with respect to the data sets and model manipulation undertaken by IEP and the CCC. Edison also claims that different load shape data was used by Edison and IEP as opposed to the CCC. Edison believes that no significant comparison can be made between the results of two simulation model outputs if the models use different load shapes.

With respect to unit commitment and dispatch, Edison notes that one major difference in the ELFIN simulation modeling and the PROMOD modeling is the treatment of "must run" units. Edison states that the "must run" designation of the coal, nuclear, some hydro, and QF resources is essentially correct. Edison asserts, however, that the "must run" designation of oil and gas units used by both the CCC and IEP is not correct. With reference to historical data, Edison would expect that the production from these units would amount to significantly less than the 72% of all oil/gas energy production projected for test year 1988.

Edison is also troubled by the fact that the CCC, IEP, and PSD simulations of the Edison system were not based on the Edison resource plan. According to Edison, these resource the price negotiated under the agreement since it is higher than the BPA MOU.

(4) QF Generation

During hearings in this proceeding, the CCC, IEP, and the CSC all challenged Edison's original forecast of 1988 QF generation. According to the CCC, an artificially high QF forecast produces lower IERs and ultimately results in underpayments to QFs.

The CCC states that Edison's short-term forecasts of expected QF generation demonstrate the uncertainty with this type of forecasting and underscore a pattern of needing to reduce forecasts to account for lower levels of actual QF generation. Specifically, Edison's forecast has ranged from a high of 14,362 gWh in its CFM-VI filing and 14,174 gWh in its 1986 Resource Plan to a low of 7,786 gWh in its April ECAC update. The CCC recommends that the Commission adopt Edison's April 8, 1987 forecast of 12,694 gWh, reflecting a number of QF start-up delays. This updated 1988 estimate is the most current forecast contained in the record and therefore the best estimate provided to the Commission.

IEP has estimated that QFs will produce 9,192 gWh for sale to Edison in 1988, of which 2,420 gWh will be paid for based on floating or variable energy prices. IEP believes these estimates are reasonable and should be adopted for two reasons. First, IEP's analysis was based on information provided by Edison and a review of Edison's initial and updated forecast reports filed in their 1987 ECAC (A.87-02-019). Second, like the CCC, IEP notes the continual updating by Edison reducing its original forecast to match more current, recorded information.

In Edison's rebuttal testimony (Exhibit 109), Edison concurs that subsequent to the development of Edison's PROMOD simulations in the fall of 1986, changes had occurred in the schedules of some of the QF resources that were expected to start operation in 1988. These changes were reflected in the latest Edison ECAC update, but were not included in the Edison's general differences may be minor in some circumstances and major in others, but without the use of consistent resource plan assumptions, exclusive of the three contracts under dispute, no valid comparison can be made.

(8) Adjusting IERs to Reflect Commission Adopted Input Assumptions

If the Commission chooses to use input assumptions different than those filed by Edison, Edison believes that the Commission must have some means for adjusting IERs. Edison therefore proposes use of Figure 3 of Exhibit 110 which shows IER sensitivity by plotting a line connecting recorded 1985 and 1986 IERs with Edison's and the CCC's forecasted 1988 IERs as a function of base loaded energy. The slope of this line is about -25 Btus/kWh per 1,000 gWh increase in base loaded energy. Any change in economy energy purchase, base load production from Edison coal and nuclear units, or QF purchases reflected in the input assumptions adopted by the Commission can be converted to the corresponding change in IERs using this linear relationship. Edison believes that the reasonableness of this approach is further enhanced by Edison having demonstrated that the CCC's and the CSC's claims of high sensitivity to changing input assumptions are contrary to the facts.

Additionally, Edison notes that only its and the CCC's (upon removing the start-up and no-load fuel adjustment) results reflect the expected decline in IERs anticipated with increasing "base loaded energy." The IER values produced by IEP, before the start-up, no-load fuel adjustment, and the PSD values are higher than 1986 recorded IERs despite projected increases in base loaded energy.

PSD disputes Edison's assertion that only its "zero-intercept" approach shows a proper trend in forecasted IERs on the basis that an increase is expected in "base loaded energy" production from 1986 to 1988. PSD counters this assertion by rate case filing. Edison therefore revised its original estimate of 14,174 gWh of QF generation for 1988 to reflect the more current information by reducing that figure by 1480 gWh. The result was Edison's acceptance of the CCC's estimate of 12,694 gWh.

(5) Price of Natural Gas

The price of natural gas is a particularly critical input assumption. It is the primary fuel used in Edison's own oil/gas generation and is, therefore, the incremental or marginal/avoided fuel. Differences between Edison, PSD, and the interested parties include both the prices assumed for the gas and the manner in which gas prices are modeled.

In determining the price of natural gas, Edison used a fuel cost of $2.94/MMBtu, which is Edison's forecasted weighted average price for gas during the test year. Edison recommends, however, that the Commission adopt the most current average price. Although Edison also forecasted an incremental cost of gas ($2.15/MMBtu), the weighted average was the only price used in its marginal energy cost calculations.

PSD used both a forecasted average price of gas at $2.52/MMBtu and a "commodity" or "dispatch" price, also called the Tier II price, of $1.996/MMBtu or 79% of the average price. It is the PSD view that while in the long term the price of gas will track the price of oil, in the near term, the existing gas competition, combined with the restructuring of the gas industry, is expected to price gas at a discount to oil. Therefore PSD's forecasted price of natural gas is 95% of its forecasted price of Low Sulphur Waxy Residual Oil (LSWR).

The CCC endorses the 1988 gas price forecast presented by PSD of $2.52/MMBtu based on PSD price and dispatch assessments. The CCC, however, challenges the accuracy of the many and varied gas price forecasts which Edison has presented in its general rate case and ECAC applications. The CCC specifically cites four different gas price forecasts which Edison has offered:

stating that even though the production from base loaded units may increase in 1988, economy energy and firm purchase contracts are forecasted to decrease. PSD points out that these decreases will have the effect of increasing the IER.

The CCC believes that despite Edison's concession that certain of the CCC's forecasts were better due to the availability of more recent data, Edison has erred by not rerunning its PROMOD model with the corrected assumptions. The CCC disputes Edison's assertion that IERs are relatively insensitive to changes in input assumptions and those changes can be reflected as proposed above by Edison. The CCC assails Edison's attempt to diminish the importance of using the corrected assumptions as undermining the very purpose of these proceedings--accurate formulation of Edison's marginal energy costs.

The CCC also takes issue with Edison's argument that increases in forecasts of base load energy production intuitively mean other parties are in error in proposing increases in the IER over the 1985 value. The CCC believes that, by taking this position, Edison has ignored the fact that other significant assumptions have drastically changed since the last general rate case and that those assumptions also affect the calculation of the IER.

The CSC, like the CCC, similarly refute the claim by Edison that changes in base load resource generation or purchased power inputs produce little change in the IER. The CSC notes that Edison's opinion, assertedly based on historical analysis, does not withstand scrutiny even when compared to Edison's own production model runs. The CSC asserts even Edison implicitly admitted in its rebuttal testimony that a sensitivity analysis using a production simulation model is the appropriate method for calculating IERs. The CSC concludes that since no such sensitivities were presented in the record, the Commission must decide the appropriate IER level based on the Edison, PSD, IEP, CCC, or CSC recommendations.

An overall gas price of $2.94/MMBtu for the original GRC application, an ECAC forecast of $2.68/MMBtu for the first five months of 1988, a revised ECAC forecast of $2.90/MMBtu, and a $2.70/MMBtu for all of 1988 used in its PROMOD simulation.

Like Edison, IEP used a weighted average gas price in its production cost analysis. PSD points out, however, that the ELFIN model used by IEP does not permit the use of a fuel dispatch price.

Edison takes issue with the use by PSD and the CCC of a Tier II price of gas for the purpose of model dispatch. Since the Commission is now paying QFs using short-run marginal costs of energy that reflect the weighted average price Edison pays for gas rather than the Tier II price, developing IERs based on models which dispatch at the Tier II price of gas would be incorrect. In reply to Edison's challenge to PSD's use of Tier II prices, PSD states that PSD's IAM model has the capability to dispatch units based on the spot price of gas. After fixing the dispatch order, however, PSD notes that the actual weighted average price of gas can then be input into the model for the purpose of marginal cost and IER calculation, a step which PSD took. In PSD's view, this modeling approach in fact most accurately reflects reality since the utility dispatchers never dispatch units based on the average price of gas. PSD further notes that it correctly modeled QF payments on the basis of the average price of gas.

(6) Minimum Load Conditions

Minimum load conditions can be defined as the point where oil and gas fired power plants either have been turned off or are being operated at their minimum level to meet system security needs or operational constraints. During minimum load conditions, low-cost purchased power may be rejected. To the extent that Edison is required by contract to purchase higher cost power during minimum load conditions, a portion of the potential cost savings is not realized.

(9) Annual IER Update

The CCC proposes that the Commission institute an annual updating procedure for the IER in order to minimize the risks associated with forecasting. For ease of implementation, the load and resource assumptions adopted in the annual ECAC proceeding could be used as the basis for the update. The utilities would then file an application proposing avoided energy payments to QFs based on the approved assumptions. The CCC recommends that the Commission adopt an annual IER in this proceeding and defer to A.82-04-044, et al., issues related to updating. The CCC notes that the same approach was used in D.86-12-091 in PG&E's last general rate case.

c. Miscellaneous Avoided Cost Issues Raised by Edison

Edison also proposed to change some of the factors which enter into the calculation of avoided energy costs. These changes are as follows:

-- Variable O&M expenses adder: $0.003/kWh
-- Oil-gas efficiency conversion factor: 1.05
-- Sub-transmission energy line loss factor: 1.023
-- Primary level energy line loss factor: 1.026

Edison asserts that no party to this proceeding has raised issue with these modifications. Edison therefore recommends their adoption.

Edison states that in an attempt to calculate the anticipated minimum load conditions Edison used a simple regression analysis methodology. Edison acknowledges that this approach would not necessarily produce an exactly correct estimate of the minimum load hours. However, the regression did show that the expected minimum load hours would increase over time and probably be at a maximum in the 1989 to 1991 time frame. Since the only major resource additions to the Edison resource plan in the next two to three years are QF resources, the correlation of increasing minimum load conditions due to QF resource additions, as Edison did, is justifiable.

The CCC objects to Edison's methodology for the following reasons: (1) Edison failed to validate its forecasts of rejected economy energy; (2) the assumptions contained in Edison's resource plans are incorrect due to erroneously high forecasts of the availability of economy energy, QF generation, and nuclear and coal generation are too high; (3) the simulations of the Edison system do not accurately reflect the operational flexibility of the system failing to account for several factors that would reduce "must run" constraints; and (4) Edison has provided no proof that its regression equation is valid. According to the CCC, it is unlikely that a simple regression over the years can be meaningful, particularly in light of the fact that the addition of SONGS 2 and 3, the Palo Verde units, and the Intermountain Power Plant Units present highly significant perturbations to the Edison system.

The CCC also refutes Edison's assertion that QFs cause minimum load conditions. Due to additions of a substantial amount of base load capacity to the Edison system in recent years and levels of new coal and nuclear resources, the CCC contends that Edison is precluded from attributing minimum load conditions to any single generation resource.

d. Proposed IER Results

The following table summarizes the results of each party's IER analysis:

Summary of IERs

Party	"QF In" Run (Btu/kWh)	"QF In/QF Out" Run (Btu/kWh) Proposed	"QF In/QF Out" Run (Btu/kWh) Unadjusted ELFIN Results[15]
Edison	9,251		
PSD	9,626	9,775	
IEP		10,147	9,511
CCC		9,988	9,369

3. Discussion

a. Computer Model and Input Assumption Access and Use

We are disheartened to be confronted in this case with basic issues related to the litigation of marginal costs which we felt had been resolved. Primary among these is the access by the parties to computer models and related data supporting testimony and recommendations in this case. In Edison's last general rate case, D.84-12-068, we had endorsed PSD's suggestion of an OII into the subject of a uniform computer model. We felt that such uniformity would end suspicion and enhance understanding of computer models. As suggested by PSD, we also directed Edison "in its next general rate case to provide related computer data upon the filing of its application" to avoid the data gathering problems PSD had experienced in that proceeding. (D.84-12-068, at p. 256.)

Since the issuance of D.84-12-068, the Legislature has also been active in the area of computer model access. Specifically, in September, 1985, the Legislature directed the

15 These are the results achieved by the CCC and IEP using the ELFIN model and their respective "QF In/QF Out" methodologies prior to the external adjustment for start-up and no-load costs.

(7) Miscellaneous Input Assumptions

In its brief Edison expressed concerns about four additional modeling or input differences: (1) heat rate input, (2) load shape data, (3) unit commitment and dispatch, and (4) choice of resource plan. Beginning with heat rate input, Edison expresses concern with respect to the data sets and model manipulation undertaken by IEP and the CCC. Edison also claims that different load shape data was used by Edison and IEP as opposed to the CCC. Edison believes that no significant comparison can be made between the results of two simulation model outputs if the models use different load shapes.

With respect to unit commitment and dispatch, Edison notes that one major difference in the ELFIN simulation modeling and the PROMOD modeling is the treatment of "must run" units. Edison states that the "must run" designation of the coal, nuclear, some hydro, and QF resources is essentially correct. Edison asserts, however, that the "must run" designation of oil and gas units used by both the CCC and IEP is not correct. With reference to historical data, Edison would expect that the production from these units would amount to significantly less than the 72% of all oil/gas energy production projected for test year 1988.

Edison is also troubled by the fact that the CCC, IEP, and PSD simulations of the Edison system were not based on the Edison resource plan. According to Edison, these resource differences may be minor in some circumstances and major in others, but without the use of consistent resource plan assumptions, exclusive of the three contracts under dispute, no valid comparison can be made.

(8) Adjusting IERs to Reflect Commission Adopted Input Assumptions

If the Commission chooses to use input assumptions different than those filed by Edison, Edison believes that the Commission must have some means for adjusting IERs. Edison

Commission to embark on a major program to assess and validate utility computer models and to improve public understanding and access to such models. Assembly Bill 475 was enacted at that time adding Section 585 and Sections 1821 through 1824 to the California Public Utilities Code. These code sections provide, among other things, that any computer model and related data base that is the basis for any testimony or exhibit shall be available to the Commission and parties to hearings to the extent necessary for cross-examination and rebuttal. The Commission is further required to adopt rules to govern access and verification of the computer models. These rules are to include procedural safeguards that protect data bases and models not owned by the public utilities.

Pursuant to AB 475, the Commission undertook and completed its first report to the Legislature on December 31, 1986. This report focused on reviewing and explaining the electric utility production cost models. Reserved to this year's (1987) study are the adoption of rules governing access to utility models.

Despite this effort, we find that little progress toward uniformity in production cost models or availability of related data has been made within the context of the general rate case. Instead of a uniform model used by all parties, we were presented with a total of four models, the efficacy of each of which was the subject of debate. Further, in spite of our admonitions to Edison in their last general rate case regarding the early provision of data related to the use of its computer model, interested parties were still without such data as hearings on the issue of marginal cost commenced.

The difficulty of assessing the validity of various computer models is made more acute in the setting of a general rate case. With a myriad of issues to hear and decide and a strict timetable with which to adhere, the Commission is ill-equipped to decide issues related to the verification of complex computer models during a general rate case. We find that this situation therefore proposes use of Figure 3 of Exhibit 110 which shows IER sensitivity by plotting a line connecting recorded 1985 and 1986 IERs with Edison's and the CCC's forecasted 1988 IERs as a function of base loaded energy. The slope of this line is about -25 Btus/kWh per 1,000 gWh increase in base loaded energy. Any change in economy energy purchase, base load production from Edison coal and nuclear units, or QF purchases reflected in the input assumptions adopted by the Commission can be converted to the corresponding change in IERs using this linear relationship. Edison believes that the reasonableness of this approach is further enhanced by Edison having demonstrated that the CCC's and the CSC's claims of high sensitivity to changing input assumptions are contrary to the facts.

Additionally, Edison notes that only its and the CCC's (upon removing the start-up and no-load fuel adjustment) results reflect the expected decline in IERs anticipated with increasing "base loaded energy." The IER values produced by IEP, before the start-up, no-load fuel adjustment, and the PSD values are higher than 1986 recorded IERs despite projected increases in base loaded energy.

PSD disputes Edison's assertion that only its "zero-intercept" approach shows a proper trend in forecasted IERs on the basis that an increase is expected in "base loaded energy" production from 1986 to 1988. PSD counters this assertion by stating that even though the production from base loaded units may increase in 1988, economy energy and firm purchase contracts are forecasted to decrease. PSD points out that these decreases will have the effect of increasing the IER.

The CCC believes that despite Edison's concession that certain of the CCC's forecasts were better due to the availability of more recent data, Edison has erred by not rerunning its PROMOD model with the corrected assumptions. The CCC disputes Edison's assertion that IERs are relatively insensitive to changes will only worsen should the possibility of an annual update of the IER in ECAC proceedings be realized. The ECAC proceeding, even more than the general rate case, is already burdened by significant time and staffing limitations.[16]

In this case, we note that the results produced by the computer models used in this proceeding were remarkably similar. However, it is not our job to guess why this result occurred, but to know. Among the reasons which suggest themselves are (1) coincidence, (2) negligible impact of utilizing either PROMOD, ELFIN, or IAM/PCAM in calculating Edison's IER, (3) negligible impact of differing input assumptions, or (4) negligible impact of differing methodologies.

It is our concern that even if all of these circumstances were true in this particular rate case, such circumstances could be non-repeating. That is, the sum total of the model, methodology, or assumption differences did not alter the IER significantly in this case, but the sum or even one of these factors in another case could yield highly dissimilar results. In attempting to forecast the future, an already speculative science, the Commission does not want to leave to chance the understanding of the tools upon which we rely to provide the adopted forecast.

For these reasons, we find that in the future general rate case and ECAC proceedings of Edison, as well as PG&E and SDG&E, all parties presenting testimony requiring the use of a production simulation model must provide a "base case" run using the same model. Each party will, of course, also have the opportunity to present testimony using its model of choice and

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16 We note that our belief regarding the possibility of an annual update of the IER will lead us to adopt an annual IER in this proceeding, as suggested by the CCC. However, whether or not this situation will actually occur is appropriately to be decided in A.82-04-044, et al.

in input assumptions and those changes can be reflected as proposed above by Edison. The CCC assails Edison's attempt to diminish the importance of using the corrected assumptions as undermining the very purpose of these proceedings--accurate formulation of Edison's marginal energy costs.

The CCC also takes issue with Edison's argument that increases in forecasts of base load energy production intuitively mean other parties are in error in proposing increases in the IER over the 1985 value. The CCC believes that, by taking this position, Edison has ignored the fact that other significant assumptions have drastically changed since the last general rate case and that those assumptions also affect the calculation of the IER.

The CSC, like the CCC, similarly refute the claim by Edison that changes in base load resource generation or purchased power inputs produce little change in the IER. The CSC notes that Edison's opinion, assertedly based on historical analysis, does not withstand scrutiny even when compared to Edison's own production model runs. The CSC asserts even Edison implicitly admitted in its rebuttal testimony that a sensitivity analysis using a production simulation model is the appropriate method for calculating IERs. The CSC concludes that since no such sensitivities were presented in the record, the Commission must decide the appropriate IER level based on the Edison, PSD, IEP, CCC, or CSC recommendations.

(9) Annual IER Update

The CCC proposes that the Commission institute an annual updating procedure for the IER in order to minimize the risks associated with forecasting. For ease of implementation, the load and resource assumptions adopted in the annual ECAC proceeding could be used as the basis for the update. The utilities would then file an application proposing avoided energy payments to QFs based on the approved assumptions. The CCC recommends that the Commission adopt an annual IER in this proceeding and defer to explain its preferences for that model. However, the requirement that the same model must be used to present a base case will aid the Commission, as a starting point, in determining whether model, assumption, or methodological differences are causing the different results. The need for such an approach may lessen over time as ours and the parties' sophistication regarding computer models increases.

To achieve our goal, we find that the model which lends itself best to our purpose is ELFIN. As has been shown in this proceeding, ELFIN is the most accessible production simulation computer model in use at the present time and has been employed for the greatest number of uses.

We note certain parties' concerns regarding the efficacy of using ELFIN for short-run marginal cost results. We believe that this shortcoming, if one exists, can be addressed by each party either suggesting a means of adjusting the model to overcome any problem or citing the deficiency as a basis for reliance on an alternate model or approach. We discuss below the propriety of adjusting the ELFIN model to reflect start-up and no-load costs.

In any event, ELFIN results will be produced by all parties and can be compared by the Commission between each party and between other model results. We remind the parties that our goal is not to endorse ELFIN over all other models, but rather to provide a common basis for the Commission to evaluate the parties' showings and to determine the proper forecasted result within the limited time frames provided by general rate case and ECAC proceedings.

Similarly, we are concerned with continued problems related to access to input assumptions. The CCC correctly notes that issues relating to updating IERs will be ultimately decided in A.82-04-044, et al. We note, however, their comment that implementation of this annual update can be "eased" by load and resource assumptions adopted in the annual ECAC proceeding being

A.82-04-44, et al., issues related to updating. The CCC notes that the same approach was used in D.86-12-091 in PG&E's last general rate case.

c. Miscellaneous Avoided Cost Issues Raised by Edison

Edison also proposed to change some of the factors which enter into the calculation of avoided energy costs. These changes are as follows:

-- Variable O&M expenses adder: $0.003/kWh

-- Oil-gas efficiency conversion factor: 1.05

-- Sub-transmission energy line loss factor: 1.023

-- Primary level energy line loss factor: 1.026

Edison asserts that no party to this proceeding has raised issue with these modifications. Edison therefore recommends their adoption.

d. Proposed IER Results

The following table summarizes the results of each party's IER analysis:

Summary of IERs

Party	"QF In" Run (Btu/kWh)	"QF In/QF Out" Run (Btu/kWh) Proposed	"QF In/QF Out" Run (Btu/kWh) Unadjusted ELFIN Results 14
Edison	9,251		
PSD	9,626	9,775	
IEP		10,147	9,511
CCC		9,988	9,369

14 These are the results achieved by the CCC and IEP using the ELFIN model and their respective "QF In/QF Out" methodologies prior to the external adjustment for start-up and no-load costs.

used as the basis for the update. What this suggestion overlooks is the process by which those assumptions were adopted--namely, through complex litigation in the ECAC. Therefore, we also believe it is necessary to provide direction in this decision to streamline that process as well. Similar to our findings on the ELFIN base case run, it is our intention that procedures similar to those adopted below for Edison's ECAC will be followed by PG&E and SDG&E in their ECAC filings and by all three utilities in their general rate case filings.

Specifically, we direct PSD for Edison's next ECAC to hold a workshop no later than one week following Edison's ECAC filing. The purpose of this workshop will be to determine the data sets, resource plans, load shape, heat rate input, unit commitment and dispatch, minimum load conditions, resource assumptions, marginal fuel assumptions, and all other pertinent data which Edison used to calculate its IER. We have included in our list the very items with which Edison took issue in this case and claimed prevented comparisons between the results of the various parties. The purpose of this workshop will not only be to obtain data which Edison used in its calculation, but to also provide a forum in which the parties can agree, to the extent possible, on the assumptions to be used and the appropriate source of those assumptions. Sufficient time will be available following the workshop for PSD and interested parties to prepare their ECAC reports and testimony.

b. Adopted Results

In this case, we have carefully reviewed the record and concluded that the IER to be used for both marginal and avoided energy costs should not result from the averaging of the parties' proposals, an alternative suggested by the outcome in D.86-08-083 (PG&E). The reasons for this approach are several. First, we believe that much of the uncertainty regarding the appropriate methodology for calculating marginal and avoided energy costs will

3. Discussion

a. Computer Model and Input Assumption Access and Use

We are disheartened to be confronted in this case with basic issues related to the litigation of marginal costs which we felt had been resolved. Primary among these is the access by the parties to computer models and related data supporting testimony and recommendations in this case. In Edison's last general rate case, D.84-12-068, we had endorsed PSD's suggestion of an OII into the subject of a uniform computer model. We felt that such uniformity would end suspicion and enhance understanding of computer models. As suggested by PSD, we also directed Edison "in its next general rate case to provide related computer data upon the filing of its application" to avoid the data gathering problems PSD had experienced in that proceeding. (D.84-12-068, at p. 256.)

Since the issuance of D.84-12-068, the Legislature has also been active in the area of computer model access. Specifically, in September, 1985, the Legislature directed the Commission to embark on a major program to assess and validate utility computer models and to improve public understanding and access to such models. Assembly Bill 475 was enacted at that time adding Section 585 and Sections 1821 through 1824 to the California Public Utilities Code. These code sections provide, among other things, that any computer model and related data base that is the basis for any testimony or exhibit shall be available to the Commission and parties to hearings to the extent necessary for cross-examination and rebuttal. The Commission is further required to adopt rules to govern access and verification of the computer models. These rules are to include procedural safeguards that protect data bases and models not owned by the public utilities.

Pursuant to AB 475, the Commission undertook and completed its first report to the Legislature on December 31, 1986. This report focused on reviewing and explaining the electric be removed this year. Second, should the IER, as we believe it will, be updated on an annual basis, we find it critical to examine the input assumptions which were used in this case and will no doubt be in issue again in any update.

Specifically, we have concluded that the Commission has endorsed the calculation of two IERs--one for marginal energy cost determinations and one for avoided energy cost determinations. This split is appropriate since the avoided energy cost is to be used to pay QFs and should in turn reflect the contribution made by the QF in avoiding utility energy costs. While the ultimate methodology used to calculate this difference will be developed and approved in A.82-04-044, et al., we find that the Commission has continued to move in the direction of applying the "QF In/QF Out" methodology for short-run, as well as for long-run, avoided energy cost calculations. (See D.85-12-108, D.86-07-004, D.86-12-091.)

As correctly stated by both the CCC and the CSC, our reliance on PROMOD and the "zero-intercept" methodology in Edison's last general rate case was primarily a default position. In particular, the "QF In/QF Out" methodology had not been adopted and the models and related methodologies available to us that proceeding were limited. This case provides a completely different scenario with several different models, methodologies, and assumptions having been presented.

We recognize that our conclusion to use different IERs for ratemaking and QF pricing represents a departure for our policy announced in Edison's last general rate case. In that proceeding, as noted by PSD and Edison, we endorsed uniformity in marginal and avoided cost results for all purposes for which these costs are used. Although practically this approach greatly simplifies our task of determining these costs, we do not believe that it allows us to meet our obligation to provide the most accurate prices to QFs based on avoided costs and, at the same time, to provide the utility production cost models. Reserved to this year's (1987) study is the adoption of rules governing access to utility models.

Despite this effort, we find that little progress toward uniformity in production cost models or availability of related data has been made within the context of the general rate case. Instead of a uniform model used by all parties, we were presented with a total of three models, the efficacy of each of which was the subject of debate. Further, in spite of our admonitions to Edison in their last general rate case regarding the early provision of data related to the use of its computer model, interested parties were still without such data as hearings on the issue of marginal cost commenced.

The difficulty of assessing the validity of various computer models is made more acute in the setting of a general rate case. With a myriad of issues to hear and decide and a strict timetable with which to adhere, the Commission is ill-equipped to decide issues related to the verification of complex computer models during a general rate case. We find that this situation will only worsen should the possibility of an annual update of the IER in ECAC proceedings be realized. The ECAC proceeding, even more than the general rate case, is already burdened by significant time and staffing limitations.[15]

In this case, we note that the results produced by the computer models used in this proceeding were remarkably similar. However, it is not our job to <u>guess</u> why this result occurred, but to <u>know</u>. Among the reasons which suggest themselves are (1) coincidence, (2) negligible impact of utilizing either PROMOD,

15 We note that our belief regarding the possibility of an annual update of the IER will lead us to adopt an annual IER in this proceeding, as suggested by the CCC. However, whether or not this situation will actually occur is appropriately to be decided in A.82-04-44, et al.

most accurate price signals to consumers regarding their electric consumption.

Unfortunately, only one party to this proceeding presented IER results based on a "QF In" (marginal cost) approach and a "QF In/QF Out" (avoided cost) approach--PSD. Fortunately, the results produced by PSD were the least controverted in this proceeding, provided the "correct trend" which would be expected from using these two approaches (a slightly higher IER using the "QF In/ QF Out" approach), were within the range of IERs proposed by the other parties, and were derived from the same models. The models and methodologies employed by PSD also appeared to present the least concern to the other parties.

In contrast, much debate centered on the propriety of the "QF In/QF Out" methodologies proposed by the CCC and IEP. We note, as we have previously, that the decision on the appropriate methodology to be applied to a "QF In/QF Out" scenario is to be reached in A.82-04-044, et al. Due to this circumstance, we will not determine whether or not the CCC and IEP properly included "existing" QFs in their implementation of this methodology.

Because ELFIN will be used to provide the "base case" IER calculations in ECAC, however, we do feel it is appropriate to examine the issue of whether the CCC's and IEP's results include a "double-counting" of start-up and no-load costs. In this regard, we believe that the record appears to support PSD's and Edison's position that such "double-counting" does result when the ELFIN model output is externally adjusted to reflect start-up and no-load costs. This effect was in fact acknowledged by IEP, but was dismissed on the grounds that such "double-counting" had an insignificant impact on overall results. As we move to a period of potential reliance on ELFIN and the "QF In/QF Out" methodology to calculated IERs for QF pricing, the fact of "double-counting," whether insignificant or not in this particular case, could become critical in the future. We therefore find that the CCC and IEP

ELFIN, or IAM/PCAM in calculating Edison's IER, (3) negligible impact of differing input assumptions, or (4) negligible impact of differing methodologies.

It is our concern that even if all of these circumstances were true in this particular rate case, such circumstances could be non-repeating. That is, the sum total of the model, methodology, or assumption differences did not alter the IER significantly in this case, but the sum or even one of these factors in another case could yield highly dissimilar results. In attempting to forecast the future, an already speculative science, the Commission does not want to leave to chance the understanding of the tools upon which we rely to provide the adopted forecast.

For these reasons, we find that in Edison's, as well as PG&E's and SDG&E's, future general rate cases, ECAC proceedings, or other proceedings designated by A.82-04-44, et al. for developing marginal or avoided energy costs, all parties presenting testimony requiring the use of a production simulation model must provide a "base case" run using the same model. Each party will, of course, also have the opportunity to present testimony using its model of choice and explain its preferences for that model. However, the requirement that the same model must be used to present a base case will aid the Commission, as a starting point, in determining whether model, assumption, or methodological differences are causing the different results. The need for such an approach may lessen over time as ours and the parties' sophistication regarding computer models increases. Additionally, work related to the implementation of AB 475 will ultimately determine the manner in which models are to be used and accessed.

To achieve our goal, we find that the model which lends itself best to our purpose is ELFIN. As has been shown in this proceeding, ELFIN is the most accessible production simulation computer model in use at the present time and has been employed for the greatest number of uses.

improperly adjusted their ELFIN results for start-up and no-load costs.

For the reasons stated above, we find that the resulting IERs proposed by PSD--9,626 Btu/kWh to be used for the marginal energy cost calculation and 9,775 Btu/kWh to be used for the avoided energy cost calculation--are reasonable and should be adopted as annual values in this proceeding. An annual IER is appropriate for adoption in this proceeding due to the likelihood of the IER being the subject of an annual update.

Our conclusion to adopt the PSD's estimates, however, should not be interpreted as approval of PSD's "QF In/QF Out" methodology, a methodology being considered with other proposals in A.82-04-044, et al. in which proceeding the "QF In/QF Out" issue will be resolved. Neither do we intend by this result to indicate adoption of all of PSD's assumptions or acceptance of Edison's position that changes in such input assumptions have little impact on the calculation of the IER.

Instead, we find that, in this particular case, PSD's numbers are most in keeping with our decision to rely on both a "QF In" approach and a "QF In/QF Out" approach, that PSD's results are clearly within a range of reasonableness based on the totality of the evidence in this proceeding, and that both IER results emanate from the same source (i.e., same model, modeling, and assumptions).

We also do not intend for our adoption of the PSD results to indicate any acquiesence to Edison's position regarding the insensitivity of the IER calculation. The sole support for this contention is apparently the closeness of the parties' recommendations. As stated previously, however, we cannot be sure if this result in this particular case will repeatedly occur. The sensitivity runs necessary to firmly decide this issue, as even Edison recognizes, are not a part of this record.

Considering the likelihood of the IER being updated on an annual basis, however, we do believe that our resolution of the

We note certain parties' concerns regarding the efficacy of using ELFIN for short-run marginal cost results. We believe that this shortcoming, if one exists, can be addressed by each party either suggesting a means of adjusting the model to overcome any problem or citing the deficiency as a basis for reliance on an alternate model or approach. We discuss below the propriety of adjusting the ELFIN model to reflect start-up and no-load costs.

In any event, ELFIN results will be produced by all parties and can be compared by the Commission between each party and between other model results. We remind the parties that our goal is not to endorse or reflect a preference ELFIN over all other models, but rather to provide a common basis for the Commission to evaluate the parties' showings and to determine the proper forecasted result within the limited time frames provided by general rate case and ECAC proceedings.

Similarly, we are concerned with continued problems related to access to input assumptions. The CCC correctly notes that issues relating to updating IERs will be ultimately decided in A.82-04-44, et al. We note, however, their comment that implementation of this annual update can be "eased" by load and resource assumptions adopted in the annual ECAC proceeding being used as the basis for the update. What this suggestion overlooks is the process by which those assumptions were adopted--namely, through complex litigation in the ECAC. Therefore, we also believe it is necessary to provide direction in this decision to streamline that process as well. Similar to our findings on the ELFIN base case run, it is our intention that procedures similar to those adopted below for Edison's ECAC will be followed by PG&E and SDG&E in their ECAC filings and by all three utilities in their general rate case filings or any filings designated by A.82-04-44 for the development of avoided or marginal energy costs.

Specifically, we direct PSD for Edison's next ECAC or forum designated in A.82-04-44, et al. for the development of IERs, assumptions at issue here will provide useful insight into the proper determination of similar assumptions in the future. In all cases, we believe that the guiding principle in evaluating input assumptions is that the best assumptions embody the most up-to-date, verifiable information.

Base Load Unit Production Assumptions. The CCC has provided the Commission with the most reasonable assumptions regarding Edison's base load unit (coal and nuclear) production. The CCC relied upon the correct standard for evaluating Edison's nuclear power plants with less than five years of operating data--the national average of similar units. For those units, 59% is the appropriate capacity factor. Based on more recent information than was used by Edison, we also adopt the CCC's assumption of a March 1, 1988, commercial operating date for the Palo Verde 3 unit. The CCC and PSD also correctly assumed an average of a 63% capacity factor for Edison's coal plants based on historical averages and consideration of major outage factors.

Economy Energy Purchases. It is in this area that we found PSD's presentation to be the weakest. We found insufficient support for PSD's dramatically different economy energy assumptions and are unpersuaded by PSD's reasoning for making those assumptions. This single problem area in PSD's showing, however, is not sufficient to alter our adoption of PSD's final overall IER results. We find instead that based on the most recently available data that Edison's estimate of 5072 gWh of PNW economy energy purchases and the CCC's estimate (based on Edison's ECAC testimony) of 4,398 gWh of PSW economy energy are reasonable.

Firm Power Purchases. The question of what is a "firm" power purchase arises not only in the context of calculating Edison's IER, but also in the context of calculating Edison's ERI used to determine avoided capacity costs. This latter calculation will be discussed in the following section; however, our

to hold a workshop no later than one week following Edison's ECAC filing. The purpose of this workshop will be to determine the data sets, resource plans, load shape, heat rate input, unit commitment and dispatch, minimum load conditions, resource assumptions, marginal fuel assumptions, and all other pertinent data which Edison used to calculate its IER. We have included in our list the very items with which Edison took issue in this case and claimed prevented comparisons between the results of the various parties.

The purpose of this workshop will not only be to obtain data which Edison used in its calculation, but to also provide a forum in which the parties can agree, to the extent possible, on the assumptions to be used and the appropriate source of those assumptions. The Director of the Commission's Advisory and Compliance Division shall appoint an aribiter for the workshop to resolve any issues related to the development of a common data set upon which agreement cannot be reached by the parties. Sufficient time will be available following the workshop for PSD and interested parties to prepare their ECAC reports and testimony.

b. Adopted Results

In this case, we have carefully reviewed the record and concluded that the IER to be used for both marginal and avoided energy costs should not result from the averaging of the parties' proposals, an alternative suggested by the outcome in D.86-08-083 (PG&E). The reasons for this approach are several. First, we believe that much of the uncertainty regarding the appropriate methodology for calculating marginal and avoided energy costs will be removed this year. Second, should the IER, as we believe it will, be updated on an annual basis, we find it critical to examine the input assumptions which were used in this case and will no doubt be in issue again in any update.

Specifically, we have concluded that the Commission has endorsed the calculation of two IERs--one for marginal energy cost determinations and one for avoided energy cost determinations.

determinations regarding Edison's "firm" power purchases in this section are equally applicable to our discussion of the ERI.[17]

We note the concerns of PSD, the CCC, the OSC, and Edison with respect to this issue. In evaluating these agreements in terms of their inclusion as firm resource assumptions used in calculating an IER, however, it is our job to determine Edison's commitment to purchase the power, rather than to adjudge the economic benefits of the agreement. In assessing whether Edison is truly obligated in a purchase, we do need to examine the totality of circumstances surrounding that contract--its status as to the two parties, its status as to the necessary governmental approval, and last, and perhaps least important in this regard, its acceptability as to price.

We find using this criteria that the BPA MOU cannot be considered a firm contract under any circumstances. Currently, the parties have reached no agreement, and Edison has acknowledged the economic impropriety of its entering the contract as first proposed. We also note PSD's concern regarding the current lack of urgency with respect to Edison signing such an agreement.

With respect to the PP&L and PGE contracts, while both contracts still require governmental review and certain price questions have been raised, we note that the parties have reached agreement and that those agreements have been tendered to the FERC. We find that this course of action indicates Edison's intent to

17 The only basis for a differing approach in evaluating the efficacy of firm purchase assumptions for calculating IERs and ERIs is that the ERI may be in effect for a longer period of time than the IER. As stated previously, only an annual IER value will be adopted in this proceeding. The period of time in which the ERI will be in effect is an issue to be resolved in A.82-04-044, et al. Currently, that period could be as long as the time between general rate cases (three years). We do not believe, however, that our conclusions would be significantly different given a longer effective period for the ERI.

This split is appropriate since the avoided energy cost is to be used to pay QFs and should in turn reflect the contribution made by the QF in avoiding utility energy costs. While the ultimate methodology used to calculate this difference will be developed and approved in A.82-04-44, et al., we find that the Commission has continued to move in the direction of applying the "QF In/QF Out" methodology for short-run, as well as for long-run, avoided energy cost calculations. (See D.85-12-108, D.86-07-004, D.86-12-091.)

As correctly stated by both the CCC and the CSC, our reliance on PROMOD and the "zero-intercept" methodology in Edison's last general rate case was primarily a default position. In particular, the "QF In/QF Out" methodology had not been adopted and the models and related methodologies available to us that proceeding were limited. This case provides a completely different scenario with several different models, methodologies, and assumptions having been presented.

We recognize that our conclusion to use different IERs for ratemaking and QF pricing represents a departure for our policy announced in Edison's last general rate case. In that proceeding, as noted by PSD and Edison, we endorsed uniformity in marginal and avoided cost results for all purposes for which these costs are used. Although practically this approach greatly simplifies our task of determining these costs, we do not believe that it allows us to meet our obligation to provide the most accurate prices to QFs based on avoided costs and, at the same time, to provide the most accurate price signals to consumers regarding their electric consumption.

Unfortunately, only one party to this proceeding presented IER results based on a "QF In" (marginal cost) approach and a "QF In/QF Out" (avoided cost) approach--PSD. Fortunately, the results produced by PSD were the least controverted in this proceeding, provided the "correct trend" which would be expected from using these two approaches (a slightly higher IER using the

pursue and honor these agreements and as such both contracts should be considered firm purchases.

QF Generation. We adopt the most recent forecast of QF generation recommended by the CCC and agreed to by Edison of 12,694 gWh.

Minimum Load Conditions. We share the CCC's concerns regarding Edison's forecast of substantial increases in minimum load conditions, Edison's reliance on a regression analysis, and Edison's attribution of minimum load conditions to any single generation resource (i.e., QFs) in the face of increases in other base load resources as well. We believe that future forecasts should provide more specific and verifiable results regarding the causes and effect of minimum load conditions.

Natural Gas Price. We find reasonable and accurate PSD's forecasted average price of gas of $2.52/MMBtu. Unlike Edison, however, we have no difficulty with PSD's use of the "dispatch" or Tier II price as an input to the IAM model in order to most accurately reflect unit dispatch. As pointed out by the CCC, the varied gas price forecasts offered by Edison offered no clear choice regarding the correct forecasted figure.

We conclude this section on marginal and avoided energy costs by adopting those portions of PSD's and Edison's Joint Exhibit 41 on those marginal energy cost issues on which these two parties agreed and which our preceding findings do not impact. We also find reasonable Edison's request to adopt its undisputed changes to the following factors which enter into the calculation of avoided energy costs--variable O&M expenses adder, oil-gas efficiency conversion factor, sub-transmission energy line loss factor, and primary level energy line loss factor.

"QF In/ QF Out" approach), were within the range of IERs proposed by the other parties, and were derived from the same models. The models and methodologies employed by PSD also appeared to present the least concern to the other parties.

In contrast, much debate centered on the propriety of the "QF In/QF Out" methodologies proposed by the CCC and IEP. We note, as we have previously, that the decision on the appropriate methodology to be applied to a "QF In/QF Out" scenario is to be reached in A.82-04-44, et al. Due to this circumstance, we will not determine whether or not the CCC and IEP properly included "existing" QFs in their implementation of this methodology.

Because ELFIN will be used to provide the "base case" IER calculations in ECAC, however, we do feel it is appropriate to examine the issue of whether the CCC's and IEP's results include a "double-counting" of start-up and no-load costs. In this regard, we believe that the record appears to support PSD's and Edison's position that some "double-counting" does result when the ELFIN model output is externally adjusted to reflect start-up and no-load costs. This effect was in fact acknowledged by IEP, but was dismissed on the grounds that such "double-counting" had an insignificant impact on overall results.

As we move to a period of potential reliance on ELFIN and the "QF In/QF Out" methodology to calculate IERs for QF pricing, the fact of "double-counting" of start-up and no-load costs in using ELFIN, whether insignificant or not in this particular case, could become critical in the future. We therefore find that the CCC and IEP failed properly to take into account the potential for double-counting and to reduce their adjustment of their proposed IERs by the amount of the double-counting.

For the reasons stated above, we find that the resulting IERs proposed by PSD--9,626 Btu/KWh to be used for the marginal energy cost calculation and 9,775 Btu/kWh to be used for the avoided energy cost calculation--are reasonable and should be

D. Marginal Demand and
Avoided Capacity Costs

1. Background

The marginal cost of demand measures the change in total costs caused by a change in demand. These costs are calculated in terms of the incremental investment in physical plant needed to serve the next unit of load, and therefore relate principally to plant associated with generating and transporting the electricity necessary to satisfy the marginal demand. Components of marginal demand costs are the marginal costs of generation, transmission, and distribution. Because of the relation between marginal distribution and marginal customer costs, the distribution component of marginal demand costs will be considered in our subsequent section on marginal customer costs.

In past general rate cases, the marginal demand costs of generation have been based on the utility's shortage costs. There has been general agreement that a suitable proxy for those costs is the annualized value of a combustion turbine.

Related to generation marginal demand costs are avoided capacity costs. Under a short-run standard offer, the payment made to QFs for capacity are based on the utility's avoided capacity cost which, like the marginal demand cost, is based on the utility's shortage costs. The annualized value of a combustion turbine is similarly used as a proxy for those costs. Because transmission and distribution costs are not avoided by utility purchases of QF power, such costs are not included in payments to QFs. Avoided capacity costs are also used in evaluating resource alternatives and demand side management programs.

While the unadjusted value of a combustion turbine has continued to serve as the basis for determining marginal demand costs, the same has not been true for the calculation of avoided capacity costs used as the basis for payments to QFs. Since Edison's last general rate case, in which such an unadjusted value

adopted as annual values in this proceeding. An annual IER is appropriate for adoption in this proceeding due to the likelihood of the IER being the subject of an annual update. The determination of the forum and timing for updating the IER, however, remain reserved for A.82-04-44, et al. Our adopted IER value should therefore remain in effect until updated as prescribed in A.82-04-44 et al.

Our conclusion to adopt the PSD's estimates, however, should not be interpreted as approval of PSD's "QF In/QF Out" methodology, a methodology being considered with other proposals in A.82-04-44, et al. in which proceeding the "QF In/QF Out" issue will be resolved. Neither do we intend by this result to indicate adoption of all of PSD's assumptions or acceptance of Edison's position that changes in such input assumptions have little impact on the calculation of the IER.

Instead, we find that, in this particular case, PSD's numbers are most in keeping with our decision to rely on both a "QF In" approach and a "QF In/QF Out" approach, that PSD's results are clearly within a range of reasonableness based on the totality of the evidence in this proceeding, and that both IER results emanate from the same source (i.e., same model, modeling, and assumptions).

We also do not intend for our adoption of the PSD results to indicate any acquiesence to Edison's position regarding the insensitivity of the IER calculation. The sole support for this contention is apparently the closeness of the parties' recommendations. As stated previously, however, we cannot be sure if this result in this particular case will repeatedly occur. The sensitivity runs necessary to firmly decide this issue, as even Edison recognizes, are not a part of this record.

Considering the likelihood of the IER being updated on an annual basis, however, we do believe that our resolution of the assumptions at issue here will provide useful insight into the proper determination of similar assumptions in the future. In all

was adopted for QF pricing, the Commission has determined that an adjustment of the combustion turbine value is necessary to reflect system reliability. Such an adjustment is generically referred to as a capacity value multiplier.

Specifically, in D.86-07-004 (A.82-04-044, et al.), the Commission noted the general agreement among the parties that a utility's shortage cost payments may be less than the annualized fixed cost of a combustion turbine depending on whether the utility's generation reserves exceed an appropriate reliability criterion. In the subsequently issued D.86-11-071, we reviewed proposals submitted by Edison, PG&E, and SDG&E for capacity value multipliers designed to reflect the system reliability of the three utilities. In that decision we indicated our intention to use, when its development was complete, an ERI based on an Expected Unserved Energy (EUE) target as the basis for adjusting the value of the combustion turbine.

The EUE is a measure of the likely quantity of unmet demand in a given timespan. The ERI is a formula that uses the EUE target of a utility to determine the value of additional capacity to that utility. An ERI based on an EUE target is therefore a means of expressing whether the value of the additional capacity on an electric utility system in a given year is the same as, greater than, or less than, the utility's marginal capacity investment, assumed to be a combustion turbine.

In D.86-11-071 we concluded that system operability, with one historical year as reference point, should be the basis at this time for developing an EUE target. If the projection of EUE for that year is less than the EUE target, then the capacity value will be less than the annualized cost of a combustion turbine. If the projection exceeds the EUE target, and if the year in question is not far enough in the future to allow the utility to build new capacity, then the capacity value of new QFs in that year will exceed such annualized cost. (D.86-11-071, at p. 9.)

cases, we believe that the guiding principle in evaluating input assumptions is that the best assumptions embody the most up-to-date, verifiable information.

Base Load Unit Production Assumptions. The CCC has provided the Commission with the most reasonable assumptions regarding Edison's base load unit (coal and nuclear) production. The CCC relied upon the correct standard for evaluating Edison's nuclear power plants with less than five years of operating data--the national average of similar units. For those units, 59% is the appropriate capacity factor. Based on more recent information than was used by Edison, we also adopt the CCC's assumption of a March 1, 1988, commercial operating date for the Palo Verde 3 unit. The CCC and PSD also correctly assumed an average of a 63% capacity factor for Edison's coal plants based on historical averages and consideration of major outage factors.

Economy Energy Purchases. It is in this area that we found PSD's presentation to be the weakest. We found insufficient support for PSD's dramatically different economy energy assumptions and are unpersuaded by PSD's reasoning for making those assumptions. This single problem area in PSD's showing, however, is not sufficient to alter our adoption of PSD's final overall IER results. We find instead that based on the most recently available data that Edison's estimate of 5072 gWh of PNW economy energy purchases and the CCC's estimate (based on Edison's ECAC testimony) of 4,398 gWh of PSW economy energy are reasonable.

Firm Power Purchases. The question of what is a "firm" power purchase arises not only in the context of calculating Edison's IER, but also in the context of calculating Edison's ERI used to determine avoided capacity costs. This latter calculation will be discussed in the following section; however, our

In D.86-11-071, while finding that all of the utilities had presented thoughtful proposals, each utility, including Edison, was directed to revise and provide further explanation of their proposals in the June and July, 1987 hearings in A.82-04-044, et al. The Commission, however, accepted in principle Edison's proposal to implement its EUE target in conjunction with a target reserve margin. This approval, however, was conditioned on Edison's valuing capacity for the selected year on whichever target resulted in a lower total EUE for that time period.

In PG&E's most recent general rate case, the Commission recognized the ongoing study of capacity value multipliers taking place in A.82-04-044, et al. The Commission concluded that in the interim the ERI methodology adopted in PG&E's last general rate case (D.83-12-068) would be used to determine the ERI adjustment factor adopted in D.86-12-091.

In an Administrative Law Judge's (ALJ) Ruling issued in this proceeding on March 4, 1987, the ALJ acknowledged that the methodology for calculating adjustments to avoided capacity costs is an issue in A.82-04-044, et al. The ALJ further stated, however, that the general rate case remained the forum for the adoption of the precise values which would be used to determine those costs. Because no capacity value multiplier had been adopted in Edison's last general rate case, as it had been for PG&E, the parties were directed to utilize an ERI adjustment, despite its on-going study in A.82-04-044, et al., in calculating Edison's avoided capacity costs. In the absence of a reasonable EUE target at the time of hearings in this proceeding, the parties were asked to present a "default position, e.g., the target reserve margin," for the Commission's consideration.

determinations regarding Edison's "firm" power purchases in this section are equally applicable to our discussion of the ERI.[16]

We note the concerns of PSD, the CCC, the CSC, and Edison with respect to this issue. In evaluating these agreements in terms of their inclusion as firm resource assumptions used in calculating an IER, however, it is our job to determine Edison's commitment to purchase the power, rather than to adjudge the economic benefits of the agreement. In assessing whether Edison is truly obligated in a purchase, we do need to examine the totality of circumstances surrounding that contract--its status as to the two parties, its status as to the necessary governmental approval, and last, and perhaps least important in this regard, its acceptability as to price.

We find using this criteria that the BPA MOU cannot be considered a firm contract under any circumstances. Currently, the parties have reached no agreement, and Edison has acknowledged the economic impropriety of its entering the contract as first proposed. We also note PSD's concern regarding the current lack of urgency with respect to Edison signing such an agreement.

With respect to the PP&L and PGE contracts, while both contracts still require governmental review and certain price questions have been raised, we note that the parties have reached agreement and that those agreements have been tendered to the FERC. We find that this course of action indicates Edison's intent to

16 The only basis for a differing approach in evaluating the efficacy of firm purchase assumptions for calculating IERs and ERIs is that the ERI may be in effect for a longer period of time than the IER. As stated previously, only an annual IER value will be adopted in this proceeding. The period of time in which the ERI will be in effect is an issue to be resolved in A.82-04-44, et al. Currently, that period could be as long as the time between general rate cases (three years). We do not believe, however, that our conclusions would be significantly different given a longer effective period for the ERI.

2. Parties Positions

a. Marginal Demand Costs

(1) Edison and PSD

Both Edison and PSD agree on the methodology and assumptions for calculating marginal demand costs of generation and transmission. Edison and PSD have used the cost of a combustion turbine as a proxy for calculating generation marginal demand cost and a regression analysis of transmission investment costs versus peak load increases for calculating transmission marginal demand costs.

In order to complete the calculation of the 1988 O&M expenses, one of the components of the marginal demand cost, O&M escalation rates were needed. PSD's O&M escalation rates differed slightly from Edison's, but Edison agreed to accept PSD's rates. The jointly proposed numbers of generation and transmission marginal demand costs are \$69.36/kW and \$33.12/kW, respectively, as shown in Tables 2 and 3 of Exhibit 41. Edison and PSD believe these numbers to be reasonable and urge their adoption by the Commission.

(2) CMA

CMA proposes that generation marginal demand costs, like avoided capacity costs should also reflect an ERI. CMA states that Edison currently has excess generating capacity so that PSD and Edison both show Edison's ERI is substantially lower than the 1.0 which it would be if an appropriate balance of loads and resources existed. CMA believes that failure to recognize the existence of excess capacity in determining the marginal demand cost of generation means that rates based on that cost will incorrectly signal the customers that the excess capacity does not exist.

CMA also states that its testimony demonstrated that the recognition of the ERI in marginal generation costs makes little difference in the revenue allocation to classes. However,

pursue and honor these agreements and as such both contracts should be considered firm purchases.

QF Generation. We adopt the most recent forecast of QF generation recommended by the CCC and agreed to by Edison of 12,694 gWh.

Minimum Load Conditions. We share the CCC's concerns regarding Edison's forecast of substantial increases in minimum load conditions, Edison's reliance on a regression analysis, and Edison's attribution of minimum load conditions to any single generation resource (i.e., QFs) in the face of increases in other base load resources as well. We believe that future forecasts should provide more specific and verifiable results regarding the causes and effect of minimum load conditions.

Natural Gas Price. We find reasonable and accurate PSD's forecasted average price of gas of $2.52/MMBtu. Unlike Edison, however, we have no difficulty with PSD's use of the "dispatch" or Tier II price as an input to the IAM model in order to most accurately reflect unit dispatch. As pointed out by the CCC, the varied gas price forecasts offered by Edison offered no clear choice regarding the correct forecasted figure.

We conclude this section on marginal and avoided energy costs by adopting those portions of PSD's and Edison's Joint Exhibit 41 on those marginal energy cost issues on which these two parties agreed and which our preceding findings do not impact. We also find reasonable Edison's request to adopt its undisputed changes to the following factors which enter into the calculation of avoided energy costs--variable O&M expenses adder, oil-gas efficiency conversion factor, sub-transmission energy line loss factor, and primary level energy line loss factor.

use of the ERI would have significant impact on rate design. CMA asserts that with generation marginal demand costs varying significantly, the appropriate allocation of Large Power revenue requirement within that class would be affected substantially. Specifically, different proportions of the class revenue requirement would be allocated to the on-peak demand portion of scheduled rates.

b. Avoided Capacity Costs

(1) Edison

It is Edison's position that it has properly implemented the Commission's D.86-07-004 and D.86-11-071 by proposing an ERI using target EUE as a basis to project the target reserve margins for future years. Edison states that its results, which stem from detailed computer modeling and the development of a mathematically equivalent linear relationship of an exponential EUE curve, should therefore be adopted.

Additionally, Edison defends the assumptions which it made in developing its proposed ERI. Edison first states that its ERI, in compliance with D.86-11-071, does represent a calculation using a group of QFs (150 MW) projected for 1988. Second, Edison asserts that its assumptions properly included the following legally binding agreement--the BPA MOU and the PP&L and PGE agreements discussed previously.

Edison contends that, in contrast to its own approach, PSD's proposal fails to meet the requirements of D.86-11-071 and fails to include consistent and appropriate resource assumptions. Edison points out that PSD's resource assumptions are neither consistent with the CEC ER-VI Report or with PSD's Resource Exhibit 51. Edison asserts that PSD has incorrectly excluded from its resource assumptions the Balsam Meadows and 550 MWs of Pacific Northwest Purchase. Edison states that, despite recognition of these errors, PSD failed to submit new or revised ERI values incorporating the needed changes.

D. Marginal Demand and Avoided Capacity Costs

1. Background

The marginal cost of demand measures the change in total costs caused by a change in demand. These costs are calculated in terms of the incremental investment in physical plant needed to serve the next unit of load, and therefore relate principally to plant associated with generating and transporting the electricity necessary to satisfy the marginal demand. Components of marginal demand costs are the marginal costs of generation, transmission, and distribution. Because of the relation between marginal distribution and marginal customer costs, the distribution component of marginal demand costs will be considered in our subsequent section on marginal customer costs.

In past general rate cases, the marginal demand costs of generation have been based on the utility's shortage costs. There has been general agreement that a suitable proxy for those costs is the annualized value of a combustion turbine.

Related to generation marginal demand costs are avoided capacity costs. Under a short-run standard offer, the payment made to QFs for capacity are based on the utility's avoided capacity cost which, like the marginal demand cost, is based on the utility's shortage costs. The annualized value of a combustion turbine is similarly used as a proxy for those costs. Because transmission and distribution costs are not avoided by utility purchases of QF power, such costs are not included in payments to QFs. Avoided capacity costs are also used in evaluating resource alternatives and demand side management programs.

While the unadjusted value of a combustion turbine has continued to serve as the basis for determining marginal demand costs, the same has not been true for the calculation of avoided capacity costs used as the basis for payments to QFs. Since Edison's last general rate case, in which such an unadjusted value

Only Edison in this proceeding raised the issue of the status of suspended Standard Offer 2. Edison is very concerned that any reinstatement of the Standard Offer 2 levelized capacity payment schedule is premature and would present a significant risk of encouraging additional QF oversubscription. Edison therefore requests that the Commission defer from taking action on reinstatement of Standard Offer 2 until necessary modifications to the standard offer are given full and due consideration in A.82-04-044, et al.

(2) PSD

PSD states that at this time it does not have the ability to calculate an ERI based on EUE. PSD has, however, developed a different methodology which relies on the difference between a utility's actual reserve margin and its target or planning reserve margin.[18]

PSD acknowledges that its method is not the one mandated by D.86-11-071, but that it is simple and straightforward, easily replicable without recourse to computer models of any type, and achieves the goal of reflecting the value of additional capacity to the utility system. PSD further testified that its approach should capture the same basic effect as an EUE based ERI.

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18 In its testimony, PSD explained that its approach uses an actual reserve margin based on the utility resource plan, adjusted as appropriate to reflect the anticipated resource situation, and the load forecast adopted by the California Energy Commission in ER 6. The target reserve margin is also based on ER 6 figures for Edison. In applying this data, the PSD concludes that if the actual reserve margin is higher than the target reserve margin by 10 percentage points or more (e.g., actual reserve margin of 31% and target of 20%), the capacity value multiplier is set at zero. While the 10% figure is based on judgment, it is PSD's opinion that it was the reasonable range within which the corresponding EUE would drop to zero. If the actual reserve margin is equal to or less than the target, the multiplier is set at one. It is a linear scale between these two points.

was adopted for QF pricing, the Commission has determined that an adjustment of the combustion turbine value is necessary to reflect system reliability. Such an adjustment is generically referred to as a capacity value multiplier.

Specifically, in D.86-07-004 (A.82-04-44, et al.), the Commission noted the general agreement among the parties that a utility's shortage cost payments may be less than the annualized fixed cost of a combustion turbine depending on whether the utility's generation reserves exceed an appropriate reliability criterion. In the subsequently issued D.86-11-071, we reviewed proposals submitted by Edison, PG&E, and SDG&E for capacity value multipliers designed to reflect the system reliability of the three utilities. In that decision we indicated our intention to use, when its development was complete, an ERI based on an Expected Unserved Energy (EUE) target as the basis for adjusting the value of the combustion turbine.

The EUE is a measure of the likely quantity of unmet demand in a given timespan. The ERI is a formula that uses the EUE target of a utility to determine the value of additional capacity to that utility. An ERI based on an EUE target is therefore a means of expressing whether the value of the additional capacity on an electric utility system in a given year is the same as, greater than, or less than, the utility's marginal capacity investment, assumed to be a combustion turbine.

In D.86-11-071 we concluded that system operability, with one historical year as reference point, should be the basis at this time for developing an EUE target. If the projection of EUE for that year is less than the EUE target, then the capacity value will be less than the annualized cost of a combustion turbine. If the projection exceeds the EUE target, and if the year in question is not far enough in the future to allow the utility to build new capacity, then the capacity value of new QFs in that year will exceed such annualized cost. (D.86-11-071, at p. 9.)

With respect to its assumptions, PSD acknowledges the inadvertent, but erroneous exclusion of the capacity of the Balsam Meadow project, inclusion of certain erroneous figures for levels of cold standby, and use of a long-term, as opposed to short-term, demand forecast. PSD further acknowledges that it did not provide new ERI values to reflect the necessary corrections. PSD states, however, that it should be very clear that these values, while not themselves on the record, are derived using the Edison resource plan contained in Exhibit 16. PSD therefore believes that its formula for calculating the ERI can be modified according to record information.

(3) CSC

The CSC states that to determine the appropriate levels of as-available capacity payments for QFs, a choice must be made between the ERI methodologies presented in the record by PSD and Edison. If PSD's methodology is selected, corrections to PSD's assumptions, as acknowledged by PSD, must be made in order to calculate the appropriate ERI. If Edison's proposed ERI methodology is selected, additional determinations must be made concerning the viability of four individual resources. According to the CSC, PSD's "uncorrected" proposed ERI for 1988 is 5%. The CSC states that this figure would increase to 43% with the required adjustments. Edison's proposed ERI for 1988 is 4% which would change to a range between 37% to 72% depending on the treatment of the four questioned resource assumptions.

The CSC asks that its position in this proceeding not be taken as an endorsement or rejection of either methodology. With that in mind, the CSC concludes that for purposes of the general rate case Edison's calculation of the ERI, with adjustments to the four input assumptions as proposed by CSC, is preferable.

According to the CSC, the fundamental shortcoming of PSD's proposed ERI methodology in this proceeding is the use of an

In D.86-11-071, while finding that all of the utilities had presented thoughtful proposals, each utility, including Edison, was directed to revise and provide further explanation of their proposals in the June and July, 1987 hearings in A.82-04-44, et al. The Commission, however, accepted in principle Edison's proposal to implement its EUE target in conjunction with a target reserve margin. This approval, however, was conditioned on Edison's valuing capacity for the selected year on whichever target resulted in a lower total EUE for that time period.

In PG&E's most recent general rate case, the Commission recognized the ongoing study of capacity value multipliers taking place in A.82-04-44, et al. The Commission concluded that in the interim the ERI methodology adopted in PG&E's last general rate case (D.83-12-068) would be used to determine the ERI adjustment factor adopted in D.86-12-091.

In an Administrative Law Judge's (ALJ) Ruling issued in this proceeding on March 4, 1987, the ALJ acknowledged that the methodology for calculating adjustments to avoided capacity costs is an issue in A.82-04-44, et al. The ALJ further stated, however, that the general rate case remained the forum for the adoption of the precise values which would be used to determine those costs. Because no capacity value multiplier had been adopted in Edison's last general rate case, as it had been for PG&E, the parties were directed to utilize an ERI adjustment, despite its on-going study in A.82-04-44, et al., in calculating Edison's avoided capacity costs. In the absence of a reasonable EUE target at the time of hearings in this proceeding, the parties were asked to present a "default position, e.g., the target reserve margin," for the Commission's consideration.

inconsistent set of data. This inconsistence, in the CSC's view, serves to artificially deflate PSD's ERI calculation.

With respect to Edison's proposed ERI, the CSC states that Edison has presented an ERI methodology which relies upon a consistent and integrated set of data and employs an analytically supportable derivation of the EUE level. The CSC found that the flaws in Edison's calculation of the capacity value multiplier did not stem from the methodology, but from Edison's input assumptions related to supposedly firm, committed resource.

In the CSC's opinion, four resources have been erroneously included in the Edison's ERI analysis: (1) the BPA MOU, (2) the PP&L agreement, (3) the PGE agreement, and (4) 45 MW of as-available capacity from cogeneration resources. The CSC believes that the Commission has made clear in D.86-07-004 and D.86-11-071 that in determining a utility's ERI resources should be evaluated on a critical planning basis and that the "QF In/QF Out" methodology should be used. In the CSC's opinion, this "bare bones" assessment necessarily calls for the inclusion of only firm, committed resources which are likely to be available in terms of both physical availability and a reasonable price. The CSC concludes that the four questioned resources cannot meet this standard. We note that these three contracts and the CSC's position with respect to their being firm purchases have been discussed previously in our section on avoided energy costs.

With respect to the inclusion by Edison of 45 MW of as-available capacity as a firm resource, the CSC states that the Commission adopted EUE formula calls for an ERI which is equal to the average EUE, calculated with and without the block of additional capacity being valued (including the QF as-available capacity) divided by the EUE target. The CSC states that Edison admitted that no QF resource was taken out of its ERI calculation even though the resource to be valued was as-available QF capacity. In the CSC's opinion, the proper calculation of the ERI therefore

2. Parties Positions

a. Marginal Demand Costs

(1) Edison and PSD

Both Edison and PSD agree on the methodology and assumptions for calculating marginal demand costs of generation and transmission. Edison and PSD have used the cost of a combustion turbine as a proxy for calculating generation marginal demand cost and a regression analysis of transmission investment costs versus peak load increases for calculating transmission marginal demand costs.

In order to complete the calculation of the 1988 O&M expenses, one of the components of the marginal demand cost, O&M escalation rates were needed. PSD's O&M escalation rates differed slightly from Edison's, but Edison agreed to accept PSD's rates. The jointly proposed numbers of generation and transmission marginal demand costs are $69.36/KW and $33.12/KW, respectively, as shown in Tables 2 and 3 of Exhibit 41. Edison and PSD believe these numbers to be reasonable and urge their adoption by the Commission.

(2) CMA

CMA proposes that generation marginal demand costs, like avoided capacity costs should also reflect an ERI. CMA states that Edison currently has excess generating capacity so that PSD and Edison both show Edison's ERI is substantially lower than the 1.0 which it would be if an appropriate balance of loads and resources existed. CMA believes that failure to recognize the existence of excess capacity in determining the marginal demand cost of generation means that rates based on that cost will incorrectly signal the customers that the excess capacity does not exist.

CMA also states that its testimony demonstrated that the recognition of the ERI in marginal generation costs makes little difference in the revenue allocation to classes. However,

calls for the exclusion of the 45 MW of as-available QF capacity identified in the Edison resource plan.

According to the CSC, exclusion of the BPA/MOU would increase Edison's ERI to 37%, with increases of an additional 6% for the exclusion of the 45 MW of QF as-available capacity, another 29% for the exclusion of the PP&L agreement, and a further 10% for the exclusion of the PGE agreement. The cumulative effect of these four adjustments would be to increase Edison's ERI to 82% in 1988.

3. Discussion

We adopt as reasonable the generation ($69.48/kW) and transmission ($33.10/kW) marginal demand costs jointly proposed by Edison and PSD, but with the O&M loading factor updated to better reflect O&M levels and adopted franchise fees in this general rate case. We find that these parties followed the appropriate methodologies in calculating generation marginal demand costs (unadjusted annualized value of a combustion turbine) and transmission marginal demand costs (regression analysis of transmission investment costs versus peak load increases).

We do not believe, however, that the record is sufficient in this proceeding to support CMA's proposal that generation marginal demand costs, like avoided capacity costs, should reflect an Energy Reliability Index. Specifically, we believe that further evidence is required to determine whether the concerns which lead to the adoption of an adjusted combustion turbine value for calculating QF capacity prices are the same for calculating marginal costs used in revenue allocation and rate design. We will, however, direct PSD and Edison to examine the issue of the propriety of reflecting the ERI adjustment in generation marginal demand costs in Edison's next general rate case.

With respect to the determination of Edison's avoided capacity costs, we believe that the starting point is the same as for the calculation of generation marginal demand costs--the annualized value of a combustion turbine. As noted above, PSD and Edison agreed to that value in Joint Exhibit 41.

use of the ERI would have significant impact on rate design. CMA asserts that with generation marginal demand costs varying significantly, the appropriate allocation of Large Power revenue requirement within that class would be affected substantially. Specifically, different proportions of the class revenue requirement would be allocated to the on-peak demand portion of scheduled rates.

b. Avoided Capacity Costs

(1) Edison

It is Edison's position that it has properly implemented the Commission's D.86-07-004 and D.86-11-071 by proposing an ERI using target EUE as a basis to project the target reserve margins for future years. Edison states that its results, which stem from detailed computer modeling and the development of a mathematically equivalent linear relationship of an exponential EUE curve, should therefore be adopted.

Additionally, Edison defends the assumptions which it made in developing its proposed ERI. Edison first states that its ERI, in compliance with D.86-11-071, does represent a calculation using a group of QFs (150 MW) projected for 1988. Second, Edison asserts that its assumptions properly included the following legally binding agreement--the BPA MOU and the PP&L and PGE agreements discussed previously.

Edison contends that, in contrast to its own approach, PSD's proposal fails to meet the requirements of D.86-11-071 and fails to include consistent and appropriate resource assumptions. Edison points out that PSD's resource assumptions are neither consistent with the CEC ER-VI Report or with PSD's Resource Exhibit 51. Edison asserts that PSD has incorrectly excluded from its resource assumptions the Balsam Meadows and 550 MWs of Pacific Northwest Purchase. Edison states that, despite recognition of these errors, PSD failed to submit new or revised ERI values incorporating the needed changes.

However, our calculation of avoided capacity costs does not end with the adoption of this value. The Commission has made quite clear that an adjustment of the combustion turbine value is appropriate to reflect system reliability. Although final approval of the methodology to be used in making this adjustment for Edison is still to be resolved in A.82-04-044, et al., it is incumbent upon the Commission to adopt an adjustment factor in this proceeding based on the parties' proposals due to the absence of a "fall-back" position to be used in the interim. As stated earlier, in PG&E's most recent general rate case, the Commission was able to rely on the ERI which had been adopted in PG&E's previous general rate case. The absence of an adjustment of the shortage cost proxy in Edison's last general rate case prevents the Commission from following the same course in this proceeding.

Based on our decisions in A.82-04-044, et al., to date, we find that the Commission in D.86-07-004 and D.86-11-071 has indicated its preference for adjusting the annualized value of a combustion turbine by using an ERI based on an EUE target. In reviewing the proposals made in this proceeding, we note that PSD has urged the adoption of its target reserve margin methodology as being more straightforward and having the same effect as an EUE based ERI. We find, however, that the Commission has not yet endorsed a "proxy" for an ERI based on an EUE target. We also believe that it was PSD's, not this Commission's, responsibility to correct the assumptions which PSD made in calculating its capacity value multiplier and to provide the Commission with the final recommended adjustment. These steps, however, were not taken by PSD, and we are not inclined to complete PSD's showing in this decision.

Additionally, in this proceeding we have been presented with an ERI based on the concepts announced by the Commission in

Only Edison in this proceeding raised the issue of the status of suspended Standard Offer 2. Edison is very concerned that any reinstatement of the Standard Offer 2 levelized capacity payment schedule is premature and would present a significant risk of encouraging additional QF oversubscription. Edison therefore requests that the Commission defer from taking action on reinstatement of Standard Offer 2 until necessary modifications to the standard offer are given full and due consideration in A.82-04-044, et al.

(2) PSD

PSD states that at this time it does not have the ability to calculate an ERI based on EUE. PSD has, however, developed a different methodology which relies on the difference between a utility's actual reserve margin and its target or planning reserve margin.[17]

PSD acknowledges that its method is not the one mandated by D.86-11-071, but that it is simple and straightforward, easily replicable without recourse to computer models of any type, and achieves the goal of reflecting the value of additional capacity to the utility system. PSD further testified that its approach should capture the same basic effect as an EUE based ERI.

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17 In its testimony, PSD explained that its approach uses an actual reserve margin based on the utility resource plan, adjusted as appropriate to reflect the anticipated resource situation, and the load forecast adopted by the California Energy Commission in ER 6. The target reserve margin is also based on ER 6 figures for Edison. In applying this data, the PSD concludes that if the actual reserve margin is higher than the target reserve margin by 10 percentage points or more (e.g., actual reserve margin of 31% and target of 20%), the capacity value multiplier is set at zero. While the 10% figure is based on judgment, it is PSD's opinion that it was the reasonable range within which the corresponding EUE would drop to zero. If the actual reserve margin is equal to or less than the target, the multiplier is set at one. It is a linear scale between these two points.

D.86-07-004 and D.86-11-071. Although this proposal, which was made by Edison, may not have changed significantly since it was first proposed in A.82-04-044, et al., we find that without a "fall back" position it is sufficient for this proceeding. As noted by the CSC, Edison has presented an ERI methodology which relies upon a consistent and integrated set of data and employs an analytically supportable derivation of the expected unserved energy level.

We note, however, the several "flaws" which the CSC has identified in Edison's input assumptions used to calculate its ERI related to firm resources. Three of these assumptions we have dealt with in our section on marginal and avoided energy costs--the BPA MOU, the PP&L agreement, and the PGE agreement. We believe that our findings regarding the "firmness" of these agreements for purposes of calculating avoided energy costs are equally applicable here. As we stated in that section, our focus in determining Edison's obligation to purchase is on the status of the agreement as to the two parties involved, the acquisition of necessary government approval, and last, but least, the price negotiated. We conclude, as we did previously, that the BPA MOU appears to be uncertain from both of these standpoints with the parties having failed to even reach an agreement. As such the BPA MOU should not be included as an input assumption in calculating the ERI.

We find, however, that the PP&L and PGE contracts have attained greater certainty--agreements have been signed and proffered for governmental approval. Although questions of the propriety of the price Edison is to pay for this power did arise, we do not believe the evidence is sufficient to warrant a finding that the resource will not be available or that Edison is not committed to purchase the power. We therefore find that the PP&L and PGE contract were properly included as input assumptions.

Finally, the CSC correctly notes that in D.86-11-071 we determined that the ERI should equal the average EUE calculated with and without the block of additional capacity being valued,

With respect to its assumptions, PSD acknowledges the inadvertent, but erroneous exclusion of the capacity of the Balsam Meadow project, inclusion of certain erroneous figures for levels of cold standby, and use of a long-term, as opposed to short-term, demand forecast. PSD further acknowledges that it did not provide new ERI values to reflect the necessary corrections. PSD states, however, that it should be very clear that these values, while not themselves on the record, are derived using the Edison resource plan contained in Exhibit 16. PSD therefore believes that its formula for calculating the ERI can be modified according to record information.

(3) <u>CSC</u>

The CSC states that to determine the appropriate levels of as-available capacity payments for QFs, a choice must be made between the ERI methodologies presented in the record by PSD and Edison. If PSD's methodology is selected, corrections to PSD's assumptions, as acknowledged by PSD, must be made in order to calculate the appropriate ERI. If Edison's proposed ERI methodology is selected, additional determinations must be made concerning the viability of four individual resources. According to the CSC, PSD's "uncorrected" proposed ERI for 1988 is 5%. The CSC states that this figure would increase to 43% with the required adjustments. Edison's proposed ERI for 1988 is 4% which would change to a range between 37% to 72% depending on the treatment of the four questioned resource assumptions.

The CSC asks that its position in this proceeding not be taken as an endorsement or rejection of either methodology. With that in mind, the CSC concludes that for purposes of the general rate case Edison's calculation of the ERI, with adjustments to the four input assumptions as proposed by CSC, is preferable.

According to the CSC, the fundamental shortcoming of PSD's proposed ERI methodology in this proceeding is the use of an

divided by the EUE target. (D.86-11-071, at p. 9.) Since the capacity being valued in this proceeding is QF as-available capacity, we concur with the CSC that Edison erred by failing to remove any as-available QF resources from its ERI calculation. We therefore adopt the CSC's recommendation of excluding 45 MW of as-available capacity from this calculation.

The results of adopting the CSC's recommendation of excluding the BPA MOU and the 45 MW of as-available capacity is to raise Edison's proposed ERI from 4% to 43%. An ERI adjustment factor of 0.43 for 1988 is therefore adopted.[19] This value will remain in effect until updated or revised as prescribed in A.82-04-044, et al.

Finally, we respond to Edison's concerns regarding reinstatement of Standard Offer 2. As Edison has correctly noted, the reinstatement of Standard Offer 2 is an action specifically reserved to A.82-04-044, et al., and will not be decided in this proceeding.

E. Marginal Distribution and Marginal Customer Costs

1. Background

As explained in the previous section, marginal distribution costs are one of the three components of the marginal cost of demand. Marginal customer costs are the costs of providing access to the utility system to an additional customer and the costs of maintaining existing customers on the system. Marginal customer costs are not intended to reflect either energy consumption or capacity demand.

Both by definition and method of calculation, marginal distribution and marginal customer costs are distinct concepts. However, because the costs of customer access to the system (a

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19 We note that the CSC has pointed out that PSD's "corrected" ERI would similarly be 43% for the test year as well.

inconsistent set of data. This inconsistence, in the CSC's view, serves to artificially deflate PSD's ERI calculation.

With respect to Edison's proposed ERI, the CSC states that Edison has presented an ERI methodology which relies upon a consistent and integrated set of data and employs an analytically supportable derivation of the EUE level. The CSC found that the flaws in Edison's calculation of the capacity value multiplier did not stem from the methodology, but from Edison's input assumptions related to supposedly firm, committed resource.

In the CSC's opinion, four resources have been erroneously included in the Edison's ERI analysis: (1) the BPA MOU, (2) the PP&L agreement, (3) the PGE agreement, and (4) 45 MW of as-available capacity from cogeneration resources. The CSC believes that the Commission has made clear in D.86-07-004 and D.86-11-071 that in determining a utility's ERI resources should be evaluated on a critical planning basis and that the "QF In/QF Out" methodology should be used. In the CSC's opinion, this "bare bones" assessment necessarily calls for the inclusion of only firm, committed resources which are likely to be available in terms of both physical availability and a reasonable price. The CSC concludes that the four questioned resources cannot meet this standard. We note that these three contracts and the CSC's position with respect to their being firm purchases have been discussed previously in our section on avoided energy costs.

With respect to the inclusion by Edison of 45 MW of as-available capacity as a firm resource, the CSC states that the Commission adopted EUE formula calls for an ERI which is equal to the average EUE, calculated with and without the block of additional capacity being valued (including the QF as-available capacity) divided by the EUE target. The CSC states that Edison admitted that no QF resource was taken out of its ERI calculation even though the resource to be valued was as-available QF capacity. In the CSC's opinion, the proper calculation of the ERI therefore

marginal customer cost) include some elements of the electric distribution system, for this purpose these two types of marginal costs must be examined together. Specifically, the Commission must determine which of those distribution costs are demand-related and which are customer-access related and if such a determination, given current accounting data, can be made.

The need to examine the separate components of marginal customer costs has arisen due to our decision in PG&E's ECAC proceeding which adopted marginal costs for PG&E's test year 1987. (D.86-08-083.) In that decision, we abandoned our previous policy of including customer costs with other costs and allocated them on a demand basis to each customer class. We determined that it was appropriate to separately identify and allocate customer costs, which are a function of the number of utility customers and not demand or energy.

In undertaking this task, we needed to resolve two issues: (1) the appropriate methodology for determining customer costs, and (2) the appropriate classification of costs as either customer-related or demand-related. For methodology, we concluded in D.86-08-083 that "a weighted average of the incremental cost for new customers and the decremental cost for existing customers... reflects the marginal customer costs attributable to each customer class." (Id., at p. 49b.) We defined the incremental cost as those costs which the utility would incur in adding a new customer, and the decremental cost as those costs which the utility would not incur if an existing customer were to leave the utility system. (Id., at p. 49a.)

In the absence of a weighted average of incremental and decremental customer costs in the PG&E proceeding, we selected the

calls for the exclusion of the 45 MW of as-available QF capacity identified in the Edison resource plan.

According to the CSC, exclusion of the BPA/MOU would increase Edison's ERI to 37%, with increases of an additional 6% for the exclusion of the 45 MW of QF as-available capacity, another 29% for the exclusion of the PP&L agreement, and a further 10% for the exclusion of the PGE agreement. The cumulative effect of these four adjustments would be to increase Edison's ERI to 82% in 1988.

3. Discussion

We adopt as reasonable the generation ($69.48/kW) and transmission ($33.10/kW) marginal demand costs jointly proposed by Edison and PSD, but with the O&M loading factor updated to better reflect O&M levels and adopted franchise fees in this general rate case. We find that these parties followed the appropriate methodologies in calculating generation marginal demand costs (unadjusted annualized value of a combustion turbine) and transmission marginal demand costs (regression analysis of transmission investment costs versus peak load increases).

We do not believe, however, that the record is sufficient in this proceeding to support CMA's proposal that generation marginal demand costs, like avoided capacity costs, should reflect an Energy Reliability Index. Specifically, we believe that further evidence is required to determine whether the concerns which lead to the adoption of an adjusted combustion turbine value for calculating QF capacity prices are the same for calculating marginal costs used in revenue allocation and rate design. We will, however, direct PSD and Edison to examine the issue of the propriety of reflecting the ERI adjustment in generation marginal demand costs in Edison's next general rate case.

With respect to the determination of Edison's avoided capacity costs, we believe that the starting point is the same as for the calculation of generation marginal demand costs--the annualized value of a combustion turbine. As noted above, PSD and Edison agreed to that value in Joint Exhibit 41.

PSD new customer profile[20] as the "best available proxy" for that number. We stated, however, that "[i]n future proceedings with a more fully developed estimate of both incremental and decremental costs, we anticipate relying on the weighted average method ... to estimate marginal customer costs." (Id.)

With respect to the identification of marginal cost components, we found the following list of customer-related costs appropriate at present for inclusion in determining marginal customer costs for revenue allocation:

1. New customer access costs including meters, service drops, and final line transformers.[21]

20 PSD recommended the use of incremental new customer costs. PSD's method for determining marginal customer costs was a two-step approach called the Directly Assignable Cost (DAC) methodology. This approach involves the calculation of variable and fixed costs assignable to a customer class. In order to identify the customers for which specific meters, service drops, and final line transformers were dedicated, PSD developed a typical customer in each class.

21 In its approach, PSD asserted that for the residential and small light and power customers, final line transformers would be classified as demand-related costs. In D.86-08-083, we found PSD's DAC methodology to be the best measure of marginal cost and adopted PSD's estimate of new incremental costs to be the proxy for the weighted average incremental/decremental cost approach endorsed by the Commission. Our use of PSD's estimate was premised on the belief that the estimate was quite conservative since it did not include line transformer costs in customer costs. The Commission learned, in a petition for rehearing of D.86-08-083 filed by TURN, that this assumption was in error and that PSD had included line transformer costs in customer costs. In D.87-05-087, we granted limited rehearing and directed PSD to recalculate and make available for comment its incremental new customer cost estimate allocating line transformer costs to demand costs rather than customer costs.

However, our calculation of avoided capacity costs does not end with the adoption of this value. The Commission has made quite clear that an adjustment of the combustion turbine value is appropriate to reflect system reliability. Although final approval of the methodology to be used in making this adjustment for Edison is still to be resolved in A.82-04-44, et al., it is incumbent upon the Commission to adopt an adjustment factor in this proceeding based on the parties' proposals due to the absence of a "fall-back" position to be used in the interim. As stated earlier, in PG&E's most recent general rate case, the Commission was able to rely on the ERI which had been adopted in PG&E's previous general rate case. The absence of an adjustment of the shortage cost proxy in Edison's last general rate case prevents the Commission from following the same course in this proceeding.

Based on our decisions in A.82-04-44, et al., to date, we find that the Commission in D.86-07-004 and D.86-11-071 has indicated its preference for adjusting the annualized value of a combustion turbine by using an ERI based on an EUE target. In reviewing the proposals made in this proceeding, we note that PSD has urged the adoption of its target reserve margin methodology as being more straightforward and having the same effect as an EUE based ERI. We find, however, that the Commission has not yet endorsed a "proxy" for an ERI based on an EUE target. We also believe that it was PSD's, not this Commission's, responsibility to correct the assumptions which PSD made in calculating its capacity value multiplier and to provide the Commission with the final recommended adjustment. These steps, however, were not taken by PSD, and we are not inclined to complete PSD's showing in this decision.

Additionally, in this proceeding we have been presented with an ERI based on the concepts announced by the Commission in

2. Replacement and improvement costs for existing customers' access equipment which includes the items above.

3. Distribution equipment which is directly assignable to a customer class.

4. Expenses which are related to meter-reading, record-keeping, and billing. (D.86-08-083, at p. 50.)

We also determined that further study of marginal customer costs was warranted. To this end, we directed PSD and PG&E to examine the subjects of record-keeping, the division of non-dedicated distribution equipment between access and demand functions, and the replacement and upgrading costs for access equipment. (Id., at pp. 51-52.)

2. Parties Positions

In this proceeding, the primary focus of the parties was on the appropriate allocation of costs between demand-related and customer access-related costs. The appropriate methodology for calculating marginal customer cost was also an issue, but no party presented direct evidence supporting an estimate of the weighted average of incremental and decremental customer costs as discussed in D.86-08-083.[22]

22 During hearings in this proceeding, TURN, who had not presented any direct showing on marginal customer costs, requested to submit rebuttal testimony to PSD's showing. Although no other interested party or PSD was given the opportunity to present rebuttal testimony, the presiding ALJ reluctantly granted TURN's request. In its "rebuttal" testimony, however, TURN sought not only to refute statements made by PSD, but also to introduce a proposed method of calculating decremental costs and a proposed weighted average of incremental/decremental costs using PSD values and TURN's decremental cost approach. Because this testimony was in fact a direct showing, for which ample time and opportunity had been given TURN, and not rebuttal to PSD's testimony, it was not

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D.86-07-004 and D.86-11-071. Although this proposal, which was made by Edison, may not have changed significantly since it was first proposed in A.82-04-44, et al., we find that without a "fall back" position it is sufficient for this proceeding. As noted by the CSC, Edison has presented an ERI methodology which relies upon a consistent and integrated set of data and employs an analytically supportable derivation of the expected unserved energy level.

We note, however, the several "flaws" which the CSC has identified in Edison's input assumptions used to calculate its ERI related to firm resources. Three of these assumptions we have dealt with in our section on marginal and avoided energy costs--the BPA MOU, the PP&L agreement, and the PGE agreement. We believe that our findings regarding the "firmness" of these agreements for purposes of calculating avoided energy costs are equally applicable here. As we stated in that section, our focus in determining Edison's obligation to purchase is on the status of the agreement as to the two parties involved, the acquisition of necessary government approval, and last, but least, the price negotiated. We conclude, as we did previously, that the BPA MOU appears to be uncertain from both of these standpoints with the parties having failed to even reach an agreement. As such the BPA MOU should not be included as an input assumption in calculating the ERI.

We find, however, that the PP&L and PGE contracts have attained greater certainty--agreements have been signed and proffered for governmental approval. Although questions of the propriety of the price Edison is to pay for this power did arise, we do not believe the evidence is sufficient to warrant a finding that the resource will not be available or that Edison is not committed to purchase the power. We therefore find that the PP&L and PGE contract were properly included as input assumptions.

Finally, the CSC correctly notes that in D.86-11-071 we determined that the ERI should equal the average EUE calculated with and without the block of additional capacity being valued,

a. Edison

With respect to the distribution component of marginal demand cost, Edison states that both Edison and PSD used a regression analysis of demand-related distribution investments versus peak load increases to calculate the distribution marginal demand costs. Both parties assumed the demand-related distribution investment costs to be the portion of the total incremental distribution investment costs that remains after removing the customer-related investment. Despite differences in opinion regarding the appropriate methodology for allocating demand and customer access costs, Edison adopted the PSD's results which were not substantially different from its own.

Edison disputes CMA's claim that the marginal demand costs recommended by PSD and Edison are overstated because the noncoincident demand on the distribution system (represented by the sum of maximum demands on the distribution substations) was not taken into account in the PSD/Edison regression analysis. Edison understands that PSD did account for the overstatement caused by the use of system peak demand in its calculation by applying a factor which recognizes the relationship between noncoincident distribution demand and system peak demand.

In calculating marginal customers costs, Edison used the minimum distribution system (MDS) method adopted by the Commission

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received into evidence. If the testimony of TURN had been heard, TURN would have been permitted an advantage that no other interested party or PSD, especially in the context of a general rate case schedule, would have or could have been granted. Further, all parties to the proceeding would have been denied the opportunity to respond to or rebut TURN's "direct showing."

divided by the EUE target. (D.86-11-071, at p. 9.) Since the capacity being valued in this proceeding is QF as-available capacity, we concur with the CSC that Edison erred by failing to remove any as-available QF resources from its ERI calculation. We therefore adopt the CSC's recommendation of excluding 45 MW of as-available capacity from this calculation.

The results of adopting the CSC's recommendation of excluding the BPA MOU and the 45 MW of as-available capacity is to raise Edison's proposed ERI from 4% to 43%. An ERI adjustment factor of 0.43 for 1988 is therefore adopted.[18] This value will remain in effect until updated or revised as prescribed in A.82-04-44, et al.

Finally, we respond to Edison's concerns regarding reinstatement of Standard Offer 2. As Edison has correctly noted, the reinstatement of Standard Offer 2 is an action specifically reserved to A.82-04-44, et al., and will not be decided in this proceeding.

E. <u>Marginal Distribution and Marginal Customer Costs</u>

1. <u>Background</u>

As explained in the previous section, marginal distribution costs are one of the three components of the marginal cost of demand. Marginal customer costs are the costs of providing access to the utility system to an additional customer and the costs of maintaining existing customers on the system. Marginal customer costs are not intended to reflect either energy consumption or capacity demand.

Both by definition and method of calculation, marginal distribution and marginal customer costs are distinct concepts. However, because the costs of customer access to the system (a

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18 We note that the CSC has pointed out that PSD's "corrected" ERI would similarly be 43% for the test year as well.

in D.92749 (OII 67).[23] Edison explains that a minimum distribution system is a hypothetical distribution system consisting of the minimum-sized components which would electrically connect customers to the Edison system and would be capable of carrying only minimal load. Since, under this method, components are minimally sized, the costs associated with the minimum distribution system are assumed to be customer-related. The determination of the marginal customer costs affects the distribution marginal demand cost which is assumed to be the distribution investment costs that remain after removing the customer-related distribution investment costs.

On the basis of accounting data alone, it is Edison's opinion that the distribution marginal customer costs cannot be separated from the distribution marginal demand costs for joint cost components such as poles, lines, and towers. Edison allocates such joint costs to customer costs on the basis of the minimum distribution system. While agreeing that there are difficulties in properly allocating the joint costs, Edison believes that PSD's methodology understates customer costs by assuming that these cost components are all demand-related costs.

Edison determined, however, that even though the methodologies proposed by Edison and PSD differed, both were largely judgmental and led to similar marginal cost results if Edison were to remove the joint costs from the calculation. On that basis and to avoid unnecessary controversy, Edison accepted PSD's marginal customer costs for this proceeding.

With respect to the incremental/decremental method of calculating marginal customer costs, Edison states that this method will not recover 100% of an incremental new investment for the

23 This method was discussed, but largely opposed by the parties to the PG&E test year 1987 general rate case. (See D.86-08-083.)

marginal customer cost) include some elements of the electric distribution system, for this purpose these two types of marginal costs must be examined together. Specifically, the Commission must determine which of those distribution costs are demand-related and which are customer-access related and if such a determination, given current accounting data, can be made.

The need to examine the separate components of marginal customer costs has arisen due to our decision in PG&E's ECAC proceeding which adopted marginal costs for PG&E's test year 1987. (D.86-08-083.) In that decision, we abandoned our previous policy of including customer costs with other costs and allocated them on a demand basis to each customer class. We determined that it was appropriate to separately identify and allocate customer costs, which are a function of the number of utility customers and not demand or energy.

In undertaking this task, we needed to resolve two issues: (1) the appropriate methodology for determining customer costs, and (2) the appropriate classification of costs as either customer-related or demand-related. For methodology, we concluded in D.86-08-083 that "a weighted average of the incremental cost for new customers and the decremental cost for existing customers... reflects the marginal customer costs attributable to each customer class." (Id., at p. 49b.) We defined the incremental cost as those costs which the utility would incur in adding a new customer, and the decremental cost as those costs which the utility would not incur if an existing customer were to leave the utility system. (Id., at p. 49a.)

In the absence of a weighted average of incremental and decremental customer costs in the PG&E proceeding, we selected the

residential class and should therefore be rejected by the Commission. Edison also objects to the Commission's consideration of the incremental/decremental method in this proceeding since it was not the subject of direct testimony and was supported in TURN's brief by arguments presented for the first time in this proceeding.

Edison also asks that the Commission reject the proposal of the Farm Bureau. Edison states that the Farm Bureau has requested that agricultural and pumping customers should not pay the same marginal customer cost as other customers due to the decrease in consumption of agricultural customers. Edison states that the effect of adopting such a proposal would be contrary to the adopted principle of marginal cost as a measure of the total cost change resulting from a change in output variables. Edison believes that it is entirely appropriate to require that agricultural and pumping customers pay the same marginal costs as other customers. Edison also notes that, despite the Farm Bureau's assertion to the contrary, PSD did determine the marginal customer costs for a typical agricultural customer based on data supplied to PSD by Edison.

b. <u>PSD</u>

In this proceeding, PSD recommends that marginal customer costs should be calculated on the basis of the typical customer approach adopted for PG&E's test year 1987 in D.86-08-083. This approach, according to PSD, identifies final line transformers, connecting service, and meters as customer access equipment. In this proceeding, PSD refers to its methodology as the "Transformer, Service Drop, and Meter" or TSM approach.

PSD further recommends the use of incremental marginal customer cost in determining marginal customer costs. It is PSD's opinion that the weighted average incremental/decremental cost methodology adopted in D.86-08-083 does not properly reflect marginal customer costs due to the systematic undercollection of plant investment which results from its use.

PSD new customer profile[19] as the "best available proxy" for that number. We stated, however, that "[i]n future proceedings with a more fully developed estimate of both incremental and decremental costs, we anticipate relying on the weighted average method ... to estimate marginal customer costs." (Id.)

With respect to the identification of marginal cost components, we found the following list of customer-related costs appropriate at present for inclusion in determining marginal customer costs for revenue allocation:

1. New customer access costs including meters, service drops, and final line transformers.[20]

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19 PSD recommended the use of incremental new customer costs. PSD's method for determining marginal customer costs was a two-step approach called the Directly Assignable Cost (DAC) methodology. This approach involves the calculation of variable and fixed costs assignable to a customer class. In order to identify the customers for which specific meters, service drops, and final line transformers were dedicated, PSD developed a typical customer in each class.

20 In its approach, PSD asserted that for the residential and small light and power customers, final line transformers would be classified as demand-related costs. In D.86-08-083, we found PSD's DAC methodology to be the best measure of marginal cost and adopted PSD's estimate of new incremental costs to be the proxy for the weighted average incremental/decremental cost approach endorsed by the Commission. Our use of PSD's estimate was premised on the belief that the estimate was quite conservative since it did not include line transformer costs in customer costs. The Commission learned, in a petition for rehearing of D.86-08-083 filed by TURN, that this assumption was in error and that PSD had included line transformer costs in customer costs. In D.87-05-087, we granted limited rehearing and directed PSD to recalculate and make available for comment its incremental new customer cost estimate allocating line transformer costs to demand costs rather than customer costs.

According to PSD, the fundamental advantages of the TSM approach are that it (1) provides a logical allocation of distribution plant between customer dedicated and common functions, (2) uses clearly assignable accounting information, and (3) yields clearly defined verifiable cost estimates. PSD asserts that those components of the distribution system which are dedicated to access by customer class include transformers (customers vary by voltage level), service drops (each customer has one for its sole use) and meters (each serves one customer). PSD points out that these components are typically sized according to the customer class virtually irrespective of load. In PSD's opinion the balance of the distribution components, referred to as the "common distribution system" (towers, poles, and lines), are shared by all customers, are sized according to expected load, and are therefore demand-related costs. PSD states that it also used an estimate of Edison's overall cost of capital to estimate annual charges for customer access equipment.

Until more accurate estimates can be determined, it is PSD's position that its proposal should be accepted as a very reasonable and balanced estimate of customer access costs. PSD notes, however, that other parties critical of the TSM approach have argued (1) that the approach fails to reflect any portion of the common distribution system (non-TSM) costs that are access-related, (2) that it does not reflect differentials in the rates at which different customer classes have added customers, and (3) that it fails to reflect only the costs of changes in customer access (the incremental/decremental method).

With respect to the first criticism, PSD acknowledges that because of geographic diversity among customers, some portion of the common distribution system is related to providing access to remotely located customers and is not exclusively demand-related. PSD states, however, that further study is required to provide the

2. Replacement and improvement costs for existing customers' access equipment which includes the items above.

3. Distribution equipment which is directly assignable to a customer class.

4. Expenses which are related to meter-reading, record-keeping, and billing. (D.86-08-083, at p. 50.)

We also determined that further study of marginal customer costs was warranted. To this end, we directed PSD and PG&E to examine the subjects of record-keeping, the division of non-dedicated distribution equipment between access and demand functions, and the replacement and upgrading costs for access equipment. (Id., at pp. 51-52.)

2. Parties Positions

In this proceeding, the primary focus of the parties was on the appropriate allocation of costs between demand-related and customer access-related costs. The appropriate methodology for calculating marginal customer cost was also an issue, but no party presented direct evidence supporting an estimate of the weighted average of incremental and decremental customer costs as discussed in D.86-08-083.[21]

21 During hearings in this proceeding, TURN, who had not presented any direct showing on marginal customer costs, requested to submit rebuttal testimony to PSD's showing. Although no other interested party or PSD was given the opportunity to present rebuttal testimony, the presiding ALJ reluctantly granted TURN's request. In its "rebuttal" testimony, however, TURN sought not only to refute statements made by PSD, but also to introduce a proposed method of calculating decremental costs and a proposed weighted average of incremental/decremental costs using PSD values and TURN's decremental cost approach. Because this testimony was in fact a direct showing, for which ample time and opportunity had been given TURN, and not rebuttal to PSD's testimony, it was not

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proper means of precisely allocating common distribution system costs.

PSD states that the second area of concern with its approach was raised by the Farm Bureau. According to PSD, the Farm Bureau asserted that marginal customer costs should be decreased for customer groups, such as agricultural and pumping customers, whose numbers are decreasing. PSD points out that the difficulty with this approach is that the marginal customer costs are calculated by using the costs of adding a new customer in order to establish the marginal cost. The marginal cost value is therefore not derived from depreciated costs on an individual customer basis.

The third objection to PSD's approach stems from TURN's assertion that marginal customer costs should be computed using the incremental/decremental method. As noted previously, it is PSD's opinion, however, that the TURN approach has one basic and fundamental flaw--the systematic undercollection of plant investment.[24]

PSD states that it does not object to the incremental/decremental method because it may not exactly yield the revenue requirement, a goal which PSD agrees with TURN is not the purpose

24 According to PSD, TURN estimates the system rate as a weighted average of the full annual access equipment charge for new customers and 25% of the full annual rental charge for existing customers. PSD states that both PSD and TURN use an annual rental charge which would just amortize an investment if applied for each and every year of the service life of the investment. This annual charge is the economic carrying charge which remains constant in real dollar terms and would represent a good approximation of a competitive market's annual rental charge. PSD applies this charge every year to every customer as it must be if investment costs are ever to be recovered. The incremental/decremental approach proposed by TURN systematically reduces the annual charge for rate determination to 25% of its necessary value whenever a customer is reclassified from "new customer" to "existing customer", which will happen with each successive rate case; thus systematic undercollection is inevitably guaranteed.

a. Edison

With respect to the distribution component of marginal demand cost, Edison states that both Edison and PSD used a regression analysis of demand-related distribution investments versus peak load increases to calculate the distribution marginal demand costs. Both parties assumed the demand-related distribution investment costs to be the portion of the total incremental distribution investment costs that remains after removing the customer-related investment. Despite differences in opinion regarding the appropriate methodology for allocating demand and customer access costs, Edison adopted the PSD's results which were not substantially different from its own.

Edison disputes CMA's claim that the marginal demand costs recommended by PSD and Edison are overstated because the noncoincident demand on the distribution system (represented by the sum of maximum demands on the distribution substations) was not taken into account in the PSD/Edison regression analysis. Edison understands that PSD did account for the overstatement caused by the use of system peak demand in its calculation by applying a factor which recognizes the relationship between noncoincident distribution demand and system peak demand.

In calculating marginal customers costs, Edison used the minimum distribution system (MDS) method adopted by the Commission

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received into evidence. If the testimony of TURN had been heard, TURN would have been permitted an advantage that no other interested party or PSD, especially in the context of a general rate case schedule, would have or could have been granted. Further, all parties to the proceeding would have been denied the opportunity to respond to or rebut TURN's "direct showing."

of marginal cost pricing. Rather, PSD objects to the method because it contains an error which invariably causes under recovery of investment costs over the service life of the capitalized investment. PSD believes that any representation of marginal cost pricing which must necessarily forfeit investment is a defective representation of an otherwise useful pricing theory.[25]

Finally, PSD asserts that marginal customer costs for streetlighting should be developed using the same TSM methodology that PSD has used in calculating marginal customer costs for all other customer groups. PSD notes, however, that this analysis is distinct from the calculation of streetlight facilities charges which represent the rental fee for the streetlight appliance and which PSD recommends should continue to be excluded from the revenue allocation process.

PSD and Edison have agreed on the TSM marginal customer cost components for streetlighting except for the cost of a Regulated Output (R.O.) transformer. Specifically, PSD has proposed to allocate part (10%) of the cost of the transformer as a marginal cost, while allocating the remainder as a facilities charge. PSD states that it has no objection to the Commission classifying the full cost of the transformer as a marginal customer cost, a position which Edison believes is more consistent with PSD's TSM approach. PSD believes, however, that its allocation more appropriately reflects the fact that the R.O. transformer has aspects of both an end-use appliance and a means of customer access. PSD states that its allocation is therefore based on the

25 PSD also notes that the marginal costs of generation demand, transmission demand and distribution demand all contain an investment component which is amortized by an annual economic carrying charge. PSD states that TURN has never explained why an incremental/decremental estimate should not also be applied to these other marginal costs.

in D.92749 (OII 67).[22] Edison explains that a minimum distribution system is a hypothetical distribution system consisting of the minimum-sized components which would electrically connect customers to the Edison system and would be capable of carrying only minimal load. Since, under this method, components are minimally sized, the costs associated with the minimum distribution system are assumed to be customer-related. The determination of the marginal customer costs affects the distribution marginal demand cost which is assumed to be the distribution investment costs that remain after removing the customer-related distribution investment costs.

On the basis of accounting data alone, it is Edison's opinion that the distribution marginal customer costs cannot be separated from the distribution marginal demand costs for joint cost components such as poles, lines, and towers. Edison allocates such joint costs to customer costs on the basis of the minimum distribution system. While agreeing that there are difficulties in properly allocating the joint costs, Edison believes that PSD's methodology understates customer costs by assuming that these cost components are all demand-related costs.

Edison determined, however, that even though the methodologies proposed by Edison and PSD differed, both were largely judgmental and led to similar marginal cost results if Edison were to remove the joint costs from the calculation. On that basis and to avoid unnecessary controversy, Edison accepted PSD's marginal customer costs for this proceeding.

With respect to the incremental/decremental method of calculating marginal customer costs, Edison states that this method will not recover 100% of an incremental new investment for the

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22 This method was discussed, but largely opposed by the parties to the PG&E test year 1987 general rate case. (See D.86-08-083.)

difference between the cost of a standard transformer which provides "access" and the cost of an R.O. transformer which provides "access" as well as the regulated output necessary to the proper functioning of the streetlight.

c. CMA

It is CMA's position that Edison erroneously agreed to PSD's marginal distribution and marginal customer cost values. CMA states that witnesses for both PSD and Edison acknowledged that some part of the common distribution system is necessary for customer access. Yet, according to CMA, PSD allocated zero percent of that system as customer costs, while Edison's original.method would have allocated 40% of that system to customer costs. CMA believes that access costs must be distinguished and allocated as customer costs, not demand costs. In CMA's opinion, Edison's original minimum distribution system analysis remains the best in this record for achieving that goal.

With respect to marginal distribution demand costs, CMA observes that PSD has determined annual marginal distribution demand costs at $37.91/kW. In its testimony, CMA concluded that a comparable cost was $22.63/kW at secondary voltage and $19.53/kW at primary voltage. CMA states that the source of the difference is in the direct incremental investment which CMA determined was $115.04/kW while PSD determined was $228.00/kW. CMA believes that, in major part, this difference is generated by PSD's allocation of all the common distribution system to demand costs instead of allocating 40% as a customer cost as Edison originally did and CMA submits is correct.

In addition, CMA contends that the appropriate load on which to regress the distribution demand costs is not system peak demand, as PSD did, but the demand on the distribution system as measured by the sum of the maximum demands on distribution substations. CMA believes that such a method is more accurate by analyzing demands on each distribution substation. CMA notes,

residential class and should therefore be rejected by the Commission. Edison also objects to the Commission's consideration of the incremental/decremental method in this proceeding since it was not the subject of direct testimony and was supported in TURN's brief by arguments presented for the first time in this proceeding.

Edison also asks that the Commission reject the proposal of the Farm Bureau. Edison states that the Farm Bureau has requested that agricultural and pumping customers should not pay the same marginal customer cost as other customers due to the decrease in consumption of agricultural customers. Edison states that the effect of adopting such a proposal would be contrary to the adopted principle of marginal cost as a measure of the total cost change resulting from a change in output variables. Edison believes that it is entirely appropriate to require that agricultural and pumping customers pay the same marginal costs as other customers. Edison also notes that, despite the Farm Bureau's assertion to the contrary, PSD did determine the marginal customer costs for a typical agricultural customer based on data supplied to PSD by Edison.

b. PSD

In this proceeding, PSD recommends that marginal customer costs should be calculated on the basis of the typical customer approach adopted for PG&E's test year 1987 in D.86-08-083. This approach, according to PSD, identifies final line transformers, connecting service, and meters as customer access equipment. In this proceeding, PSD refers to its methodology as the "Transformer, Service Drop, and Meter" or TSM approach.

PSD further recommends the use of incremental marginal customer cost in determining marginal customer costs. It is PSD's opinion that the weighted average incremental/decremental cost methodology adopted in D.86-08-083 does not properly reflect marginal customer costs due to the systematic undercollection of plant investment which results from its use.

however, that its approach could have been improved by data from substations being accumulated by Edison in a more complete form.

d. Industrial Users

Like CMA, the IU objects to PSD's marginal customer cost proposal on the basis that it allocates all of the costs of the common distribution system to demand and none to customer costs, even though it is undisputed that the distribution system serves both a load and access function. The IU believes that the effect of this error was demonstrated by their witness who compared the total marginal costs for Edison's major customer classes incorporating, first, the PSD's customer costs and second, Edison's originally proposed customer costs which included 40% of common distribution costs. The IU states that this comparison revealed that, by using the Edison values, the result would be a marked increase in the amount of the costs allocated to residential customers and a decrease in the costs allocated to all of the other major customer classes, large power included.

IU, however, stops short of endorsing Edison's approach. Instead, in its testimony, IU proposed two alternate methods (the minimum customer method and the zero intercept method) which are variations of the MDS method. According to the IU, time constraints prohibited the refinement of marginal customer cost data in this proceeding using either of these approaches. IU therefore asks that if the allocation of revenue adopted in this case is to be phased-in over more than one year, any revenue allocation after the initial allocation be based on a marginal cost study that attempts to more accurately estimate the full level of marginal customer costs.

e. Farm Bureau

The Farm Bureau states that marginal cost pricing, in theory and as adopted by the Commission, is a method which measures how a change in a variable component of providing electric service affects the total cost of the electric service. To remain true to

According to PSD, the fundamental advantages of the TSM approach are that it (1) provides a logical allocation of distribution plant between customer dedicated and common functions, (2) uses clearly assignable accounting information, and (3) yields clearly defined verifiable cost estimates. PSD asserts that those components of the distribution system which are dedicated to access by customer class include transformers (customers vary by voltage level), service drops (each customer has one for its sole use) and meters (each serves one customer). PSD points out that these components are typically sized according to the customer class virtually irrespective of load. In PSD's opinion the balance of the distribution components, referred to as the "common distribution system" (towers, poles, and lines), are shared by all customers, are sized according to expected load, and are therefore demand-related costs. PSD states that it also used an estimate of Edison's overall cost of capital to estimate annual charges for customer access equipment.

Until more accurate estimates can be determined, it is PSD's position that its proposal should be accepted as a very reasonable and balanced estimate of customer access costs. PSD notes, however, that other parties critical of the TSM approach have argued (1) that the approach fails to reflect any portion of the common distribution system (non-TSM) costs that are access-related, (2) that it does not reflect differentials in the rates at which different customer classes have added customers, and (3) that it fails to reflect only the costs of changes in customer access (the incremental/decremental method).

With respect to the first criticism, PSD acknowledges that because of geographic diversity among customers, some portion of the common distribution system is related to providing access to remotely located customers and is not exclusively demand-related. PSD states, however, that further study is required to provide the

the marginal cost methodology of pricing the total electric service on the margin, the Farm Bureau states that each component (i.e., demand, energy, and customer costs) must be measured on the margin.

The Farm Bureau believes, however, that this analysis distorts the true cost of service for any class of customers who are not causing the variables of demand, energy, or customer to increase. In the Farm Bureau's opinion, a marginal cost pricing formula which fails to consider the fact that a "plateauing" of a class of service creates a counter-balancing effect on that class's demand, energy and/or customer costs will cause the class to receive a cost allocation above its true cost of service.

It is the Farm Bureau's position that the Commission should amend its marginal cost pricing methodology to recognize the proposition that increases which are caused by specific groups of customers must be billed directly to those customers. Until that time, in the Farm Bureau's opinion, a class of service remaining constant or lowering its demand, such as the agricultural class, will receive cost allocations which it did not cause the system to incur.

According to the Farm Bureau, for demand costs, the matching of causation and cost dictates that new additions be charged to those customer classes causing the new load. For customer costs, Farm Bureau states that both PSD's and Edison's calculations fail to recognize the significant decrease in agricultural customers in over the last ten years and the retention by the agricultural class of transformers, service drops and meters far beyond their book life.

f. TURN

TURN opposes the calculation of marginal customer costs based on the costs of adding new customers to the Edison system. TURN states that the cost of adding new customers to the Edison system (incremental customer cost) is much greater than the cost saved by the utility when an existing customer leaves (decremental

proper means of precisely allocating common distribution system costs.

PSD states that the second area of concern with its approach was raised by the Farm Bureau. According to PSD, the Farm Bureau asserted that marginal customer costs should be decreased for customer groups, such as agricultural and pumping customers, whose numbers are decreasing. PSD points out that the difficulty with this approach is that the marginal customer costs are calculated by using the costs of adding a new customer in order to establish the marginal cost. The marginal cost value is therefore not derived from depreciated costs on an individual customer basis.

The third objection to PSD's approach stems from TURN's assertion that marginal customer costs should be computed using the incremental/decremental method. As noted previously, it is PSD's opinion, however, that the TURN approach has one basic and fundamental flaw--the systematic undercollection of plant investment.[23]

PSD states that it does not object to the incremental/decremental method because it may not exactly yield the revenue requirement, a goal which PSD agrees with TURN is not the purpose

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23 According to PSD, TURN estimates the system rate as a weighted average of the full annual access equipment charge for new customers and 25% of the full annual rental charge for existing customers. PSD states that both PSD and TURN use an annual rental charge which would just amortize an investment if applied for each and every year of the service life of the investment. This annual charge is the economic carrying charge which remains constant in real dollar terms and would represent a good approximation of a competitive market's annual rental charge. PSD applies this charge every year to every customer as it must be if investment costs are ever to be recovered. The incremental/decremental approach proposed by TURN systematically reduces the annual charge for rate determination to 25% of its necessary value whenever a customer is reclassified from "new customer" to "existing customer", which will happen with each successive rate case; thus systematic undercollection is inevitably guaranteed.

customer costs). Basing revenue allocation on incremental customer costs therefore sends the wrong price signal as it overstates the savings to the utility when a customer leaves the system.

It is TURN's position that if marginal customer costs are to be used in this proceeding, the Commission should follow the incremental/decremental approach adopted for PG&E in D.86-08-083 and recently reaffirmed on rehearing in D.87-05-076. In TURN's opinion, this approach is a better proxy for the economically efficient method of charging new customers a hook-up fee and existing customers decremental customer costs. TURN further notes that in D.86-03-083, the Commission recognized that using incremental customer costs in revenue allocation provides an inaccurate price signal to existing customers (D.86-08-083, at p. 49).

TURN also responds to PSD's claim that blending incremental and decremental cost will result in revenue undercollection. TURN states that PSD's objection is irrelevant because the purpose of marginal cost pricing is to provide accurate price signals and not to recover the utility's investment. TURN also argues that PSD has also dramatically overstated the amount of revenue shortfall assertedly caused by the incremental/decremental approach by using a model which fails to recognize that the number of existing customers far exceeds the number of new customers on the Edison system. Moreover, TURN states that the shortfall only exists if rates are set exactly at marginal cost. If rates are set on the basis of Equal Percent of Marginal Cost (EPMC), TURN believes that there may be not shortfall at all from using the incremental/ decremental method.

TURN also asserts that all parties except itself have overstated incremental marginal customer costs. According to TURN, the PSD method of calculating marginal costs incorrectly assumes that customers would rent interconnection equipment from utilities rather than purchase this equipment. Since the cost of purchasing

of marginal cost pricing. Rather, PSD objects to the method because it contains an error which invariably causes under recovery of investment costs over the service life of the capitalized investment. PSD believes that any representation of marginal cost pricing which must necessarily forfeit investment is a defective representation of an otherwise useful pricing theory.[24]

Finally, PSD asserts that marginal customer costs for streetlighting should be developed using the same TSM methodology that PSD has used in calculating marginal customer costs for all other customer groups. PSD notes, however, that this analysis is distinct from the calculation of streetlight facilities charges which represent the rental fee for the streetlight appliance and which PSD recommends should continue to be excluded from the revenue allocation process.

PSD and Edison have agreed on the TSM marginal customer cost components for streetlighting except for the cost of a Regulated Output (R.O.) transformer. Specifically, PSD has proposed to allocate part (10%) of the cost of the transformer as a marginal cost, while allocating the remainder as a facilities charge. PSD states that it has no objection to the Commission classifying the full cost of the transformer as a marginal customer cost, a position which Edison believes is more consistent with PSD's TSM approach. PSD believes, however, that its allocation more appropriately reflects the fact that the R.O. transformer has aspects of both an end-use appliance and a means of customer access. PSD states that its allocation is therefore based on the

24 PSD also notes that the marginal costs of generation demand, transmission demand and distribution demand all contain an investment component which is amortized by an annual economic carrying charge. PSD states that TURN has never explained why an incremental/decremental estimate should not also be applied to these other marginal costs.

equipment is clearly lower than the rental cost assumed by the PSD, TURN believes that utilities would be forced by competition to offer rates below the PSD's incremental rental rate.

Despite PSD's arguments to the contrary, TURN does not believe that customer ownership of access equipment presents any insurmountable problems. According to TURN, requirements of safety, reliability and billing integrity could all be met by allowing customer access equipment to be serviced only by qualified companies and limiting meter servicing, if necessary, to the utility.

Finally, TURN notes that in granting its request for rehearing of D.86-08-083, the Commission ordered the PSD to recalculate incremental customer cost by omitting the cost of transformers (D.87-05-076). Based on Table 4-1 of PSD's Exhibit 60-D, TURN states that, by removing transformer costs, which PSD did not do in calculating its incremental marginal customer costs, the residential customer cost proposed by PSD would be lowered by approximately one-third.

3. Discussion

It had been our opinion that in D.86-08-083 we had reached certain significant and final conclusions regarding the use and determination of marginal customer costs. Specifically, in that decision we found, as recited at the beginning of this section, (1) that marginal customer costs should be included in the revenue allocation process, (2) that the weighted average of incremental and decremental costs should be used to calculate marginal customer costs, and (3) that customer-related costs should include meters, service drops, and final line transformers; the costs of replacing and improving such access equipment; and distribution equipment directly assignable to a customer class.

While the parties to this proceeding have followed our direction in D.86-08-083 with respect to two of these findings, all, except for TURN, have ignored the Commission's statement that

difference between the cost of a standard transformer which provides "access" and the cost of an R.O. transformer which provides "access" as well as the regulated output necessary to the proper functioning of the streetlight.

c. CMA

It is CMA's position that Edison erroneously agreed to PSD's marginal distribution and marginal customer cost values. CMA states that witnesses for both PSD and Edison acknowledged that some part of the common distribution system is necessary for customer access. Yet, according to CMA, PSD allocated zero percent of that system as customer costs, while Edison's original method would have allocated 40% of that system to customer costs. CMA believes that access costs must be distinguished and allocated as customer costs, not demand costs. In CMA's opinion, Edison's original minimum distribution system analysis remains the best in this record for achieving that goal.

With respect to marginal distribution demand costs, CMA observes that PSD has determined annual marginal distribution demand costs at $37.91/kW. In its testimony, CMA concluded that a comparable cost was $22.63/kW at secondary voltage and $19.53/kW at primary voltage. CMA states that the source of the difference is in the direct incremental investment which CMA determined was $115.04/kW while PSD determined was $228.00/kW. CMA believes that, in major part, this difference is generated by PSD's allocation of all the common distribution system to demand costs instead of allocating 40% as a customer cost as Edison originally did and CMA submits is correct.

In addition, CMA contends that the appropriate load on which to regress the distribution demand costs is not system peak demand, as PSD did, but the demand on the distribution system as measured by the sum of the maximum demands on distribution substations. CMA believes that such a method is more accurate by analyzing demands on each distribution substation. CMA notes,

in future proceedings "we anticipate relying on the weighted average method to estimate marginal customer costs." (D.86-08-083, at p. 49b.) In this case, we have been presented with no direct evidence or "a fully developed estimate" of both incremental and decremental costs nor, obviously, a weighted average of those costs.[26] Instead, the record in this proceeding includes only the following: (1) Edison's use of the MDS approach which we did not adopt in D.86-08-083 to calculate marginal customer costs; (2) PSD's proposed incremental customer cost estimate, a cost which was adopted in D.86-08-083 as a "proxy" for incremental/decremental cost approach only because of the absence of a weighted average of those two costs; (3) Farm Bureau's proposed retreat from marginal cost pricing for agricultural and pumping customers; and (4) TURN's endorsement of the incremental/decremental approach unsupported by any direct evidence on the calculation of those costs.

In response to arguments made by PSD and Edison that the incremental/decremental method will undercollect the revenue requirement, we concur with TURN that the question of revenue shortfalls is not necessarily relevant in determining the appropriate methodology for calculating marginal costs. As we have repeatedly stated, marginal costs are used in ratemaking in order to provide the most accurate price signals regarding the customer's electric consumption. In adopting the incremental/decremental approach, we believed and remain convinced that this goal is achieved by relying on a methodology which most precisely determines the marginal cost related to customer access and maintenance on the utility system.

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26 We note, for Edison's benefit, that its customary argument that prior rate cases of other utilities are not precedential with respect to its own general rate case does not apply here. As our review of D.86-08-083 makes clear, that decision was clearly intended to have precedential effect.

however, that its approach could have been improved by data from substations being accumulated by Edison in a more complete form.

d. Industrial Users

Like CMA, the IU objects to PSD's marginal customer cost proposal on the basis that it allocates all of the costs of the common distribution system to demand and none to customer costs, even though it is undisputed that the distribution system serves both a load and access function. The IU believes that the effect of this error was demonstrated by their witness who compared the total marginal costs for Edison's major customer classes incorporating, first, the PSD's customer costs and second, Edison's originally proposed customer costs which included 40% of common distribution costs. The IU states that this comparison revealed that, by using the Edison values, the result would be a marked increase in the amount of the costs allocated to residential customers and a decrease in the costs allocated to all of the other major customer classes, large power included.

IU, however, stops short of endorsing Edison's approach. Instead, in its testimony, IU proposed two alternate methods (the minimum customer method and the zero intercept method) which are variations of the MDS method. According to the IU, time constraints prohibited the refinement of marginal customer cost data in this proceeding using either of these approaches. IU therefore asks that if the allocation of revenue adopted in this case is to be phased-in over more than one year, any revenue allocation after the initial allocation be based on a marginal cost study that attempts to more accurately estimate the full level of marginal customer costs.

e. Farm Bureau

The Farm Bureau states that marginal cost pricing, in theory and as adopted by the Commission, is a method which measures how a change in a variable component of providing electric service affects the total cost of the electric service. To remain true to

Further, as noted previously, we have no "fully developed" estimates of the incremental cost for new customers and the decremental cost for existing customers. Without these estimates, it is difficult to make the required comparison between the PSD's approach and the weighted average incremental/decremental approach which we adopted in D.86-08-083 to determine whether and to what extent systematic undercollection is caused by using this latter methodology. We note that Edison's and PSD's concerns regarding revenue shortfalls appear to relate more to TURN's approach to calculating decremental costs than to fundamental problems with the weighted average methodology itself. If this circumstance is in fact the case, we note that neither PSD nor Edison is in any way precluded from taking into account and adjusting for the potential for undercollection in determining its estimates of incremental and decremental customer costs in future proceedings.

We also reject the Farm Bureau's apparent attempt to return to embedded costs to measure the customer costs to be attributed to agricultural customers. Whether a class is increasing or decreasing, we have concluded that the most equitable way in which to determine class revenue responsibility is by viewing the impact of such changes not in isolation, but in terms of their effect on a utility's total costs. If the Farm Bureau believes that some "special treatment" of agricultural customers is warranted, this goal is better achieved within the specific rate schedules under which those customers' rates are determined.[27]

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27 We note that the Farm Bureau has identified certain costs (i.e., those associated with noncoincident demand) as not among those imposed on the utility system by the agricultural class. We are concerned, however, that, in order to be consistent, if other costs, such as those related to access, were borne entirely by the

(Footnote continues on next page)

the marginal cost methodology of pricing the total electric service on the margin, the Farm Bureau states that each component (i.e., demand, energy, and customer costs) must be measured on the margin.

The Farm Bureau believes, however, that this analysis distorts the true cost of service for any class of customers who are not causing the variables of demand, energy, or customer to increase. In the Farm Bureau's opinion, a marginal cost pricing formula which fails to consider the fact that a "plateauing" of a class of service creates a counter-balancing effect on that class's demand, energy and/or customer costs will cause the class to receive a cost allocation above its true cost of service.

It is the Farm Bureau's position that the Commission should amend its marginal cost pricing methodology to recognize the proposition that increases which are caused by specific groups of customers must be billed directly to those customers. Until that time, in the Farm Bureau's opinion, a class of service remaining constant or lowering its demand, such as the agricultural class, will receive cost allocations which it did not cause the system to incur.

According to the Farm Bureau, for demand costs, the matching of causation and cost dictates that new additions be charged to those customer classes causing the new load. For customer costs, Farm Bureau states that both PSD's and Edison's calculations fail to recognize the significant decrease in agricultural customers in over the last ten years and the retention by the agricultural class of transformers, service drops and meters far beyond their book life.

f. TURN

TURN opposes the calculation of marginal customer costs based on the costs of adding new customers to the Edison system. TURN states that the cost of adding new customers to the Edison system (incremental customer cost) is much greater than the cost saved by the utility when an existing customer leaves (decremental

Given the choices that have been presented in this proceeding, it appears that only PSD has provided us with a "usable" proxy for the weighted average of incremental and decremental costs. Specifically, we find that PSD's determination of incremental costs based on the TSM approach is closest to the intent of D.86-08-083.

As we mentioned previously, however, our adoption of PSD's approach for PG&E was premised on PSD's incremental marginal customer cost estimate being conservative. We concluded that this conservatism had resulted from PSD's treatment of final line transformers for the residential and small light and power customers as demand-related costs. A limited rehearing of D.86-08-083 was necessary to ensure that numbers reflecting this treatment of line transformers were used in determining PG&E's marginal customer costs.

To bring Edison's marginal customer costs closer to those intended to be implemented following D.86-08-083, we will also adopt PSD's incremental customer cost estimate exclusive of final line transformers as the proxy for the weighted average of Edison's incremental and decremental customer costs. We do not find, however, a basis to discriminate between classes for purposes of this exclusion and will use an incremental cost estimate which excludes the line transformers for all customer classes. This approach will ensure equal treatment of all customer classes in the revenue allocation process.

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agricultural class in proportion to their being incurred by that class, a significant burden would be created for agricultural customers which is otherwise currently offset by our use of marginal costs.

customer costs). Basing revenue allocation on incremental customer costs therefore sends the wrong price signal as it overstates the savings to the utility when a customer leaves the system.

It is TURN's position that if marginal customer costs are to be used in this proceeding, the Commission should follow the incremental/decremental approach adopted for PG&E in D.86-08-083 and recently reaffirmed on rehearing in D.87-05-076. In TURN's opinion, this approach is a better proxy for the economically efficient method of charging new customers a hook-up fee and existing customers decremental customer costs. TURN further notes that in D.86-03-083, the Commission recognized that using incremental customer costs in revenue allocation provides an inaccurate price signal to existing customers (D.86-08-083, at p. 49).

TURN also responds to PSD's claim that blending incremental and decremental cost will result in revenue undercollection. TURN states that PSD's objection is irrelevant because the purpose of marginal cost pricing is to provide accurate price signals and not to recover the utility's investment. TURN also argues that PSD has also dramatically overstated the amount of revenue shortfall assertedly caused by the incremental/decremental approach by using a model which fails to recognize that the number of existing customers far exceeds the number of new customers on the Edison system. Moreover, TURN states that the shortfall only exists if rates are set exactly at marginal cost. If rates are set on the basis of Equal Percent of Marginal Cost (EPMC), TURN believes that there may be not shortfall at all from using the incremental/ decremental method.

TURN also asserts that all parties except itself have overstated incremental marginal customer costs. According to TURN, the PSD method of calculating marginal costs incorrectly assumes that customers would rent interconnection equipment from utilities rather than purchase this equipment. Since the cost of purchasing

We find that, by ordering the removal of transformer costs, the resolution of the marginal customer cost issue for Edison will be similar to that which we adopted by PG&E. For the next general rate cases for both utilities, we direct all parties to follow the methodology adopted in D.86-08-083 and reaffirmed in this order based on the weighted average of the utility's incremental and decremental customer costs. Once these costs are properly before us in future proceedings, it will hopefully no longer be necessary to rely on a proxy which excludes an otherwise properly recognized customer access cost (i.e., final line transformers) from the calculation of marginal customer costs.

We also find that until further studies are completed PSD has made a good faith effort to attribute those costs to customers which are directly assignable to customer access. PSD has followed the list which we adopted in D.86-08-083 and has continued to include distribution costs for which combined demand and customer-access functions cannot now be accurately segregated.

We also concur with PSD's approach to calculating marginal customer costs for streetlight customers and PSD's inclusion of those costs in the revenue allocation process. We believe that PSD's effort to differentiate between the dual functions of the R.O. transformer (access-related and end-use-related) is appropriate. This approach is not only consistent with our efforts to specifically identify marginal customer costs, but also with our continued exclusion from the revenue allocation process of streetlight facilities charges as costs associated with an end-use.

Finally, we are not insensitive to the concerns of the industrial customers regarding the need to ensure that all costs, even those also related to distribution, be properly included in marginal customer costs. To this end and recognizing the need for further refinements in the development of marginal customer costs, we direct Edison to work with PSD to:

equipment is clearly lower than the rental cost assumed by the PSD, TURN believes that utilities would be forced by competition to offer rates below the PSD's incremental rental rate.

Despite PSD's arguments to the contrary, TURN does not believe that customer ownership of access equipment presents any insurmountable problems. According to TURN, requirements of safety, reliability and billing integrity could all be met by allowing customer access equipment to be serviced only by qualified companies and limiting meter servicing, if necessary, to the utility.

Finally, TURN notes that in granting its request for rehearing of D.86-08-083, the Commission ordered the PSD to recalculate incremental customer cost by omitting the cost of transformers (D.87-05-076). Based on Table 4-1 of PSD's Exhibit 60-D, TURN states that, by removing transformer costs, which PSD did not do in calculating its incremental marginal customer costs, the residential customer cost proposed by PSD would be lowered by approximately one-third.

3. <u>Discussion</u>

It had been our opinion that in D.86-08-083 we had reached certain significant and final conclusions regarding the use and determination of marginal customer costs. Specifically, in that decision we found, as recited at the beginning of this section, (1) that marginal customer costs should be included in the revenue allocation process, (2) that the weighted average of incremental and decremental costs should be used to calculate marginal customer costs, and (3) that customer-related costs should include meters, service drops, and final line transformers; the costs of replacing and improving such access equipment; and distribution equipment directly assignable to a customer class.

While the parties to this proceeding have followed our direction in D.86-08-083 with respect to two of these findings, all, except for TURN, have ignored the Commission's statement that

"1. Establish record-keeping that will clearly

    (1) identify customer hook-up costs and

    (2) distinguish new from existing customers.

"2. Analyze non-dedicated distribution equipment for access versus demand function.

"3. Identify replacement and upgrading costs for access equipment." (D.86-08-083, at p. 52.)

With respect to the calculation of marginal distribution costs, we adopt the agreement reached by PSD and Edison modified, as necessary, to reflect our adopted marginal customer costs exclusive of transformers. Edison and PSD appropriately utilized a regression analysis of demand-related distribution investments versus peak load increases to calculate the distribution marginal demand costs. For Edison's next general rate case, we will direct PSD and Edison to examine the effects of basing the regression on the load measured by the sum of the maximum demands on distribution substations as proposed by CMA. As stated previously, we have endorsed PSD's approach to classifying demand and customer access costs which produced distribution marginal demand costs to which Edison acceded.

F. Costing Periods

In this section, we will adopt the appropriate basis upon which to differentiate marginal costs on the basis of time-of-use (TOU) or costing periods. A costing period is defined as a group of contiguous hours which are combined and treated as a single unit when allocating system costs and developing a rate design. Time-differentiated marginal costs are an important factor in developing rate design, evaluating conservation and load management programs, and making other resource decisions.

in future proceedings "we anticipate relying on the weighted average method to estimate marginal customer costs." (D.86-08-083, at p. 49b.) In this case, we have been presented with no direct evidence or "a fully developed estimate" of both incremental and decremental costs nor, obviously, a weighted average of those costs.[25] Instead, the record in this proceeding includes only the following: (1) Edison's use of the MDS approach which we did not adopt in D.86-08-083 to calculate marginal customer costs; (2) PSD's proposed incremental customer cost estimate, a cost which was adopted in D.86-08-083 as a "proxy" for incremental/decremental cost approach only because of the absence of a weighted average of those two costs; (3) Farm Bureau's proposed retreat from marginal cost pricing for agricultural and pumping customers; and (4) TURN's endorsement of the incremental/decremental approach unsupported by any direct evidence on the calculation of those costs.

In response to arguments that the incremental/decremental method will undercollect the revenue requirement, we concur with TURN that the question of revenue shortfalls is not necessarily relevant in determining the appropriate methodology for calculating marginal costs. As we have repeatedly stated, marginal costs are used in ratemaking in order to provide the most accurate price signals regarding the customer's electric consumption. In adopting the incremental/decremental approach, we believed and remain convinced that this goal is achieved by relying on a methodology which most precisely determines the marginal cost related to customer access and maintenance on the utility system.

25 We note, for Edison's benefit, that its customary argument that prior rate cases of other utilities are not precedential with respect to its own general rate case does not apply here. As our review of D.86-08-083 makes clear, that decision was clearly intended to have precedential effect.

The goal in establishing costing periods is to group hours by time of day and by season so as to maximize differences in the costing patterns between periods and minimize the differences between hours within periods. Data taken into account in determining the appropriate costing periods include marginal costs, load curves, loss of load probabilities, and excess load probabilities. Consideration is also given to the ease of customer understanding of the periods, the continuity over time, the ability to avoid rate shock solely from changing time periods, and the degree of administrative burden imposed on the utility from any changes.

1. Parties Positions

a. Edison and PSD

In Exhibit 41, jointly sponsored by Edison and PSD, these two parties compromised on a proposal to modify the existing TOU periods for cost analysis and rate design purposes. Both parties had originally sponsored independent proposals based on analyses of 1988 loads, hourly marginal cost, and loss of load probability data. The proposal to which Edison and PSD agreed would merge the existing winter on-peak and mid-peak TOU periods, leaving unchanged the other TOU periods.

According to Edison and PSD, during the hearings the only party to express concern with the proposed costing periods was the CLECA/CSPG. Through their cross-examination of the PSD and Edison witnesses sponsoring Exhibit 41, these organizations indicated a preference to shorten the summer on-peak period as originally proposed by PSD. In reply, Edison testified that the shortening originally proposed had not been based on unequivocal data and could bring about load shifting that would require a longer on-peak period in the next general rate case.

Both Edison and PSD note that no party, however, made any affirmative request for costing periods different than those identified in Exhibit 41. Edison and PSD therefore ask the

Further, as noted previously, we have no "fully developed" estimates of the incremental cost for new customers and the decremental cost for existing customers. Without these estimates, it is difficult to make the required comparison between the PSD's approach and the weighted average incremental/ decremental approach which we adopted in D.86-08-083 to determine whether and to what extent systematic undercollection is caused by using this latter methodology. We note that Edison's and PSD's concerns regarding revenue shortfalls appear to relate more to TURN's approach to calculating decremental costs than to fundamental problems with the weighted average methodology itself. If this circumstance is in fact the case, we note that neither PSD nor Edison is in any way precluded from taking into account and adjusting for the potential for undercollection in determining its estimates of incremental and decremental customer costs in future proceedings.

We also reject the Farm Bureau's apparent attempt to return to embedded costs to measure the customer costs to be attributed to agricultural customers. Whether a class is increasing or decreasing, we have concluded that the most equitable way in which to determine class revenue responsibility is by viewing the impact of such changes not in isolation, but in terms of their effect on a utility's total costs. If the Farm Bureau believes that some "special treatment" of agricultural customers is warranted, this goal is better achieved within the specific rate schedules under which those customers' rates are determined.[26]

26 We note that the Farm Bureau has identified certain costs (i.e., those associated with noncoincident demand) as not among those imposed on the utility system by the agricultural class. We are concerned, however, that, in order to be consistent, if other costs, such as those related to access, were borne entirely by the

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Commission to adopt their joint proposal to merge winter on-peak and mid-peak costing periods.

In its brief Edison also responds to a proposal made by IEP during the hearings, not with respect to costing periods for marginal costs, but with respect to the development of a "super off-peak" period for avoided cost pricing for QFs. IEP's recommendation, which is based on producing more accurate price signals, would consist of adding a super off-peak period for QFs for the hours from 1:00 a.m. to 5:00 a.m. every day.

Edison believes, however, that the results of IEP's analysis do not support its recommendation. Edison states that IEP had found the difference between avoided energy cost in the off-peak and super off-peak periods to be only 0.05 cents/kWh in the summer and 0.06 cents/kWh in the winter. Edison concludes that this small differential between costs in the off-peak and super off-peak periods does not justify the change requested by IEP.

b. CMA

CMA states that time-differentiated costs are particularly susceptible to variations in data. For this reason, CMA is concerned that current procedures for determining costing and rating periods are "highly judgmental." CMA therefore urges the Commission to consider more formally articulated principles for developing costing periods.

Given the choices that have been presented in this proceeding, it appears that only PSD has provided us with a "usable" proxy for the weighted average of incremental and decremental costs. Specifically, we find that PSD's determination of incremental costs based on the TSM approach is closest to the intent of D.86-08-083.

As we mentioned previously, however, our adoption of PSD's approach for PG&E was premised on PSD's incremental marginal customer cost estimate being conservative. We concluded that this conservatism had resulted from PSD's treatment of final line transformers for the residential and small light and power customers as demand-related costs. A limited rehearing of D.86-08-083 was necessary to ensure that numbers reflecting this treatment of line transformers were used in determining PG&E's marginal customer costs.

To bring Edison's marginal customer costs closer to those intended to be implemented following D.86-08-083, we will also adopt PSD's incremental customer cost estimate exclusive of final line transformers as the proxy for the weighted average of Edison's incremental and decremental customer costs. We do not find, however, a basis to discriminate between classes for purposes of this exclusion and will use an incremental cost estimate which excludes the line transformers for all customer classes. This approach will ensure equal treatment of all customer classes in the revenue allocation process.

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agricultural class in proportion to their being incurred by that class, a significant burden would be created for agricultural customers which is otherwise currently offset by our use of marginal costs.

c. CLECA/CSPG

CLECA/CSPG agree with the position of PSD and Edison, as set forth in Exhibit 41, that current cost data supports consolidation of winter on- and mid-peak TOU periods into a single mid-peak period. CLECA/CSPG indicate their concern, however, with the failure to completely analyze the merits of reducing the summer on-peak TOU period to five hours from six hours, as first proposed by PSD. CLECA/CSPG believe that this issue should be considered more fully in the next Edison general rate case to determine whether a shorter summer on-peak period is viable for large power customers.

2. Discussion

The need for time-differentiated marginal costs is clear. By adopting such an approach, TOU customers will be provided with the most accurate price signals regarding their electric consumption and can in turn make informed economic decisions about that consumption. We do not in this proceeding, however, have a record on which to base any refinements to costing periods beyond those to which Edison and PSD have agreed. We encourage CMA, CLECA/CSPG, or any other interested party, as well as PSD and Edison, to provide us with information in Edison's next general rate case aimed at improving the judgmental science of developing costing periods and in turn furthering our goal of marginal cost ratemaking. Such an inquiry could include an examination of whether a shorter summer on-peak period is viable for large power customers as suggested by CLECA/CSPG.

Until that time, we will adopt the costing periods to which PSD and Edison have agreed in Joint Exhibit 41 which include the single change of combining the winter on-peak and mid-peak periods. We concur with Edison, however, that the record does not support the addition of a super-off-peak period for QFs on Edison's system at this time. This finding does not preclude IEP or other

We find that, by ordering the removal of transformer costs, the resolution of the marginal customer cost issue for Edison will be similar to that which we adopted by PG&E. For the next general rate cases of each electric utility, we direct all parties to follow and provide numerical estimates based on the methodology adopted in D.86-08-083 and reaffirmed in this order based on the weighted average of the utility's incremental and decremental customer costs. Once these costs are properly before us in future proceedings, it will hopefully no longer be necessary to rely on a proxy which excludes an otherwise properly recognized customer access cost (i.e., final line transformers) from the calculation of marginal customer costs.

We also find that until further studies are completed PSD has made a good faith effort to attribute those costs to customers which are directly assignable to customer access. PSD has followed the list which we adopted in D.86-08-083 and has continued to include distribution costs for which combined demand and customer-access functions cannot now be accurately segregated.

We also concur with PSD's approach to calculating marginal customer costs for streetlight customers and PSD's inclusion of those costs in the revenue allocation process. We believe that PSD's effort to differentiate between the dual functions of the R.O. transformer (access-related and end-use-related) is appropriate. This approach is not only consistent with our efforts to specifically identify marginal customer costs, but also with our continued exclusion from the revenue allocation process of streetlight facilities charges as costs associated with an end-use.

Finally, we are not insensitive to the concerns of the industrial customers regarding the need to ensure that all costs, even those also related to distribution, be properly included in marginal customer costs. To this end and recognizing the need for interested parties, however, from renewing this proposal in Edison's next general rate case.

G. Adopted Marginal Costs

Marginal costs, once determined by the Commission, are ultimately used to apportion the adopted revenue requirement among customer classes. The following table presents our adopted annual marginal energy, demand, and customer costs.

further refinements in the development of marginal customer costs, we direct Edison to work with PSD to:

"1. Establish record-keeping that will clearly

(1) identify customer hook-up costs and

(2) distinguish new from existing customers.

"2. Analyze non-dedicated distribution equipment for access versus demand function.

"3. Identify replacement and upgrading costs for access equipment." (D.86-08-083, at p. 52.)

With respect to the calculation of marginal distribution costs, we adopt the agreement reached by PSD and Edison modified, as necessary, to reflect our adopted marginal customer costs exclusive of transformers. Edison and PSD appropriately utilized a regression analysis of demand-related distribution investments versus peak load increases to calculate the distribution marginal demand costs. For Edison's next general rate case, we will direct PSD and Edison to examine the effects of basing the regression on the load measured by the sum of the maximum demands on distribution substations as proposed by CMA. As stated previously, we have endorsed PSD's approach to classifying demand and customer access costs which produced distribution marginal demand costs to which Edison acceded.

F. Costing Periods

In this section, we will adopt the appropriate basis upon which to differentiate marginal costs on the basis of time-of-use (TOU) or costing periods. A costing period is defined as a group of contiguous hours which are combined and treated as a single unit when allocating system costs and developing a rate design. Time-differentiated marginal costs are an important factor in developing

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SUMMARY OF ADOPTED MARGINAL COSTS
TEST YEAR 1988

MARGINAL ENERGY COSTS	($/kWh)
Generation	0.0273
Transmission	0.0280
Distribution:	
Primary	0.0290
Secondary	0.0295
MARGINAL DEMAND COSTS	($/kW/YEAR)
Generation	69.48
Transmission	33.10
Distribution:	
Primary	45.06
Secondary	52.22
MARGINAL CUSTOMER COSTS	($/CUSTOMER/YEAR)
Domestic	43.44
GS-1	43.10
GS-2	211.65
PA-1	128.53
PA-2	214.37
TOU-8-Secondary	1342.82
TOU-8-Primary	2139.68
TOU-8-Subtransmission	2139.68
LS-3-Primary	317.88
LS-3-Secondary	80.04
	($/LAMP/YEAR)
LS-1	3.10
LS-2-Primary	7.32
LS-2-Secondary	5.34
OL-1	3.40
DWL-A	3.40
DWL-B	3.40
DWL-C	0.00

rate design, evaluating conservation and load management programs, and making other resource decisions.

The goal in establishing costing periods is to group hours by time of day and by season so as to maximize differences in the costing patterns between periods and minimize the differences between hours within periods. Data taken into account in determining the appropriate costing periods include marginal costs, load curves, loss of load probabilities, and excess load probabilities. Consideration is also given to the ease of customer understanding of the periods, the continuity over time, the ability to avoid rate shock solely from changing time periods, and the degree of administrative burden imposed on the utility from any changes.

1. <u>Parties Positions</u>

a. <u>Edison and PSD</u>

In Exhibit 41, jointly sponsored by Edison and PSD, these two parties compromised on a proposal to modify the existing TOU periods for cost analysis and rate design purposes. Both parties had originally sponsored independent proposals based on analyses of 1988 loads, hourly marginal cost, and loss of load probability data. The proposal to which Edison and PSD agreed would merge the existing winter on-peak and mid-peak TOU periods, leaving unchanged the other TOU periods.

According to Edison and PSD, during the hearings the only party to express concern with the proposed costing periods was the CLECA/CSPG. Through their cross-examination of the PSD and Edison witnesses sponsoring Exhibit 41, these organizations indicated a preference to shorten the summer on-peak period as originally proposed by PSD. In reply, Edison testified that the shortening originally proposed had not been based on unequivocal data and could bring about load shifting that would require a longer on-peak period in the next general rate case.

X. Revenue Allocation

A. Introduction

Revenue allocation is the process by which the total adopted revenue requirement is divided up among the various customer classes (inter-class) and among schedules within a customer class (intra-class). For purposes of revenue allocation, Edison's ratepayers have been classified into the following customer groups: domestic, small and medium light and power, large power, agricultural and pumping, and street and area lighting. Issues related to revenue allocation include the methodology to be used in allocating the revenue requirement; the manner in which that methodology is to be implemented; and the propriety of applying the same methodology to both inter-class and intra-class revenue allocation and including all customer classes (i.e., streetlight customers) in the revenue allocation.

In recent years the Commission has adhered to a policy that, to the extent practical, total revenue should be allocated to ratepayers on the basis of their share of the utility's marginal cost. As explained in our prior section on marginal cost, we believe that the reliance on marginal cost principles achieves equity in rates by relating the costs imposed on the utility system to the customer responsible for those costs.

In determining the appropriate methodology to use in allocating revenues, the Commission has had to balance its goal of achieving marginal cost ratemaking against the potentially negative impact on certain customer groups of restructuring revenue responsibilities. Among the methods considered by the Commission over the last several years have been the Equal Percent of Marginal Cost (EPMC) approach, the System Average Percentage Change (SAPC) approach, and a weighted average combination of the two.

EPMC allocates the revenue requirement on an equal basis relative to the marginal cost-based burden each customer class

Both Edison and PSD note that no party, however, made any affirmative request for costing periods different than those identified in Exhibit 41. Edison and PSD therefore ask the Commission to adopt their joint proposal to merge winter on-peak and mid-peak costing periods.

In its brief Edison also responds to a proposal made by IEP during the hearings, not with respect to costing periods for marginal costs, but with respect to the development of a "super off-peak" period for avoided cost pricing for QFs. IEP's recommendation, which is based on producing more accurate price signals, would consist of adding a super off-peak period for QFs for the hours from 1:00 a.m. to 5:00 a.m. every day.

Edison believes, however, that the results of IEP's analysis do not support its recommendation. Edison states that IEP had found the difference between avoided energy cost in the off-peak and super off-peak periods to be only 0.05 cents/kWh in the summer and 0.06 cents/kWh in the winter. Edison concludes that this small differential between costs in the off-peak and super off-peak periods does not justify the change requested by IEP.

b. CMA

CMA states that time-differentiated costs are particularly susceptible to variations in data. For this reason, CMA is concerned that current procedures for determining costing and rating periods are "highly judgmental." CMA therefore urges the Commission to consider more formally articulated principles for developing costing periods.

c. CLECA/CSPG

CLECA/CSPG agree with the position of PSD and Edison, as set forth in Exhibit 41, that current cost data supports consolidation of winter on- and mid-peak TOU periods into a single mid-peak period. CLECA/CSPG indicate their concern, however, with the failure to completely analyze the merits of reducing the summer on-peak TOU period to five hours from six hours, as first proposed

imposes on the system. SAPC adjusts existing revenue responsibilities for each customer class or schedule by the overall average percentage change in revenue requirement.

Most recently, for PG&E we concluded that our goal of marginal cost ratemaking could be achieved only by the adoption of the EPMC methodology for both inter-class and intra-class revenue allocation. In adopting a full EPMC methodology for PG&E, however, we recognized the need for moderating the effects which such an approach would have on certain customer classes. We therefore determined that the adopted EPMC revenue allocation should be phased-in prior to the next general rate case and that a cap limiting the percentage by which the average class rate could change over the SAPC for the forecast period (1987) should be used. Specifically, we found reasonable a 5 percentage point cap over the system average increase for classes other than agriculture, and a 2.5 percentage point cap over SAPC for agriculture. Based on the revenue requirement adopted in PG&E, the only classes which ultimately required any capping were the residential (5%) and agricultural (2.5%) classes. (See D.86-08-083, at pp. 67 - 67a.)

In D.86-08-083, we concluded that our approach to implementing EPMC for PG&E would achieve our goal of a marginal cost-based revenue allocation without a significant detrimental impact on any customer class. Nevertheless, while we adopted a cap for the 1987 forecast period, we declined to adopt any caps in that proceeding for the 1988 and 1989 periods. Parties were given the opportunity to renew such proposals, if necessary, in subsequent PG&E ECAC proceedings.

Following D.86-08-083, we issued D.87-05-071 in R.86-10-001, the Commission's rulemaking on revisions to electric

by PSD. CLECA/CSPG believe that this issue should be considered more fully in the next Edison general rate case to determine whether a shorter summer on-peak period is viable for large power customers.

2. Discussion

The need for time-differentiated marginal costs is clear. By adopting such an approach, TOU customers will be provided with the most accurate price signals regarding their electric consumption and can in turn make informed economic decisions about that consumption. We do not in this proceeding, however, have a record on which to base any refinements to costing periods beyond those to which Edison and PSD have agreed. We encourage CMA, CLECA/CSPG, or any other interested party, as well as PSD and Edison, to provide us with information in Edison's next general rate case aimed at improving the judgmental science of developing costing periods and in turn furthering our goal of marginal cost ratemaking. Such an inquiry could include an examination of whether a shorter summer on-peak period is viable for large power customers as suggested by CLECA/CSPG.

Until that time, we will adopt the costing periods to which PSD and Edison have agreed in Joint Exhibit 41 which include the single change of combining the winter on-peak and mid-peak periods. We concur with Edison, however, that the record does not support the addition of a super-off-peak period for QFs on Edison's system at this time. This finding does not preclude IEP or other interested parties, however, from renewing this proposal in Edison's next general rate case.

G. Adopted Marginal Costs

Marginal costs, once determined by the Commission, are ultimately used to apportion the adopted revenue requirement among customer classes. The following table presents our adopted annual marginal energy, demand, and customer costs.

utility ratemaking mechanisms.[28] In D.87-05-071, the Commission focused on rules aimed, among other things, at addressing the threat of customers' bypassing the electric utilities' systems in favor of self-generation.[29] Our particular concern, as explained in D.87-05-071, is that a customer with self-generation costs exceeding the utility's short-run marginal costs will bypass the utility system (uneconomic bypass). When this situation occurs, we have found that the customer's self-generation results in "an inefficient allocation of society's resources." (D.87-05-071, at p. 3.)

Included in the policies announced in D.87-05-071 to address the problems created by bypass was our endorsement of utility revenue allocations based on EPMC. We cited the following reasons as support for "embracing EPMC as a guiding principle for revenue allocation" (Id. at p. 5): (1) EPMC provides a fair way of relating each class's revenue requirement to the costs of providing service to that class; (2) EPMC helps reduce inter-class subsidies that distort price signals and thus result in inefficiencies to the detriment of society in general; and (3) EPMC is effective in bringing rates closer to marginal costs in precisely those customer classes most likely to bypass the utility system.

B. Adopted Revenue Allocation Methodology

Against this background, it is clear that we are fully committed to the EPMC approach for revenue allocation as the most accurate way to reflect costs customers impose on the system and as an effective response to the threat of bypass. Our intentions are

28 This proceeding is also known as the "3-Rs" (risk, return, and ratemaking) rulemaking.

29 The subject of bypass, to the extent that it affects this proceeding, is discussed in a separate section of this decision.

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SUMMARY OF ADOPTED MARGINAL COSTS
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MARGINAL CUSTOMER COSTS	($/CUSTOMER/YEAR)
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GS-2	211.65
PA-1	128.53
PA-2	214.37
TOU-8-Secondary	1342.82
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TOU-8-Subtransmission	2139.68
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LS-1	3.10
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LS-2-Secondary	5.34
OL-1	3.40
DWL-A	3.40
DWL-B	3.40
DWL-C	0.00

apparently well-known to the parties in this proceeding who almost unanimously endorsed an allocation of Edison's revenue requirement based on EPMC.[30]

Only one party to this proceeding, ACWA, endorsed a different approach. Specifically, ACWA recommended that class cost responsibility be based on an equal rate of return methodology. As Edison correctly points out this approach is based on the utility's embedded costs, a basis for ratemaking which the Commission has clearly rejected in favor of marginal cost. ACWA's arguments concerning the potential long-term negative impact on certain customer classes of adopting an EPMC revenue allocation could have been more constructively applied to proposals relating to the implementation of EPMC.

We therefore adopt in this proceeding a full EPMC approach for allocating Edison's revenue requirement. Our adoption of this methodology, however, as explained in the succeeding sections, does not end the discussion of revenue allocation. In fact, the use of EPMC requires the Commission to resolve such critical issues as the manner in which it will be implemented and the extent to which it will be applied to all customer classes and to all rate schedules within those classes.

C. Implementation of EPMC Revenue Allocation

It is the issue of implementation of a full EPMC revenue allocation for Edison which was the center of debate in this proceeding. The reason for this controversy is clear.

30 The IU organization notes that while it has traditionally advocated the use of the utility's actual or embedded cost as the most appropriate basis for revenue allocation, it joins CMA, CLECA/CSPG, FEA, PSD, and Edison in supporting a revenue allocation based on full EPMC. IU states that its support is based on the substantial similarity in results of embedded cost and marginal cost-based analyses and the potential of an EPMC methodology providing accurate price signals and avoiding uneconomic bypass.

X. Revenue Allocation

A. Introduction

Revenue allocation is the process by which the total adopted revenue requirement is divided up among the various customer classes (inter-class) and among schedules within a customer class (intra-class). For purposes of revenue allocation, Edison's ratepayers have been classified into the following customer groups: domestic, small and medium light and power, large power, agricultural and pumping, and street and area lighting. Issues related to revenue allocation include the methodology to be used in allocating the revenue requirement; the manner in which that methodology is to be implemented; and the propriety of applying the same methodology to both inter-class and intra-class revenue allocation and including all customer classes (i.e., streetlight customers) in the revenue allocation.

In recent years the Commission has adhered to a policy that, to the extent practical, total revenue should be allocated to ratepayers on the basis of their share of the utility's marginal cost. As explained in our prior section on marginal cost, we believe that the reliance on marginal cost principles achieves equity in rates by relating the costs imposed on the utility system to the customer responsible for those costs.

In determining the appropriate methodology to use in allocating revenues, the Commission has had to balance its goal of achieving marginal cost ratemaking against the potentially negative impact on certain customer groups of restructuring revenue responsibilities. Among the methods considered by the Commission over the last several years have been the Equal Percent of Marginal Cost (EPMC) approach, the System Average Percentage Change (SAPC) approach, and a weighted average combination of the two.

EPMC allocates the revenue requirement on an equal basis relative to the marginal cost-based burden each customer class

Specifically, the adoption of EPMC for Edison as the exclusive basis for revenue allocation, even if implemented over a period of years, will result in a significant rearrangement of revenue responsibility among Edison's customer groups. This impact is in part due to the historic allocation of Edison's revenues on a basis other than EPMC. In Edison's last general rate case, for instance, an allocation formula of a weighted average of 5% EPMC, 95% SAPC, was adopted. (D.84-12-068 at pp. 270-271.)

As a result, Edison's present rates are currently quite far from EPMC. Our move to EPMC could therefore result in significant increases to the domestic class and substantial decreases for the large power class. The Commission must consider if and to what extent these shifts in revenue responsibility should be mitigated in implementing EPMC.

1. <u>Parties Positions</u>

a. <u>Edison</u>

Edison has determined that it is necessary to mitigate the adverse bill impacts on certain customers that would result from an immediate implementation of a full EPMC revenue allocation methodology. To this end, Edison proposes a three-year phase-in plan resulting in a full EPMC revenue allocation by 1990.

Edison's phase-in proposal calls for three annual revenue allocation adjustments. The first of these would take place in the test year 1988 when the total January 1, 1988 revenue requirement, including the revenue requirement adopted in this proceeding, would be allocated on the basis of a weighted average of 2/3 SAPC and 1/3 EPMC. The revenue requirement for 1989 would be allocated on the basis of a weighted average of 1/3 SAPC and 2/3 EPMC, with full EPMC achieved by 1990. In support of its approach, Edison states that its phase-in methodology: (1) treats all customer and rate groups equitably and consistently since they all steadily converge on full EPMC; (2) is understandable and easily applied; and (3) best ensures the achievement of full EPMC within three years.

imposes on the system. SAPC adjusts existing revenue responsibilities for each customer class or schedule by the overall average percentage change in revenue requirement.

Most recently, for PG&E we concluded that our goal of marginal cost ratemaking could be achieved only by the adoption of the EPMC methodology for both inter-class and intra-class revenue allocation. In adopting a full EPMC methodology for PG&E, however, we recognized the need for moderating the effects which such an approach would have on certain customer classes. We therefore determined that the adopted EPMC revenue allocation should be phased-in prior to the next general rate case and that a cap limiting the percentage by which the average class rate could change over the SAPC for the forecast period (1987) should be used. Specifically, we found reasonable a 5 percentage point cap over the system average increase for classes other than agriculture, and a 2.5 percentage point cap over SAPC for agriculture. Based on the revenue requirement adopted in PG&E, the only classes which ultimately required any capping were the residential and small light and power (5%) and agricultural (2.5%) classes. (See D.86-08-083, at pp. 67 - 67a.)

In D.86-08-083, we concluded that our approach to implementing EPMC for PG&E would achieve our goal of a marginal cost-based revenue allocation without a significant detrimental impact on any customer class. Nevertheless, while we adopted a cap for the 1987 forecast period, we declined to adopt any caps in that proceeding for the 1988 and 1989 periods. Parties were given the opportunity to renew such proposals, if necessary, in subsequent PG&E ECAC proceedings.

Following D.86-08-083, we issued D.87-05-071 in R.86-10-001, the Commission's rulemaking on revisions to electric

Edison has further proposed that the EPMC phase-in be implemented in the next two Attrition Rate Adjustment (ARA) filings (i.e, 1989 and 1990). Edison supports the use of the ARA proceeding because it is the forum in which a complete update of base rate factors is developed. According to Edison, the ARA is also based on a calendar year which more naturally fits with the forecast process of billing determinants and base rate costs. Edison rejects using the ECAC to implement the phase-in on the grounds that such an approach would unnecessarily complicate the already burdened ECAC proceeding.

With respect to PSD's proposed method of applying "caps" in phasing-in EPMC, Edison states that the adoption of this approach for PG&E in D.86-08-083 is not dispositive of the propriety of applying a similar methodology to Edison. Edison notes the following differences between the PG&E proceeding and the present one: (1) PG&E was requesting a significant decrease in revenues while Edison is requesting an increase, and (2) PG&E's present rate revenues were much closer to EPMC to begin with than are Edison's present rate revenues.

Edison further cites three shortcomings with the PSD approach. First, Edison states that PSD's methodology would result in some rate groups initially moving further away from EPMC. Second, Edison believes that it is unlikely that PSD can achieve its objective of reaching full EPMC by 1990, citing PSD testimony that an increase or decrease beyond a certain range would mean that full EPMC could not be reached using the proposed PSD caps. Third, Edison warns that PSD's proposal to forecast the third year's revenue requirement is an overly complicated process.

Edison also rejects the proposals of other parties, like CMA and FEA, who suggest a more rapid movement to EPMC. Edison believes that a more immediate move to full EPMC will result in severe bill impacts for such customer groups as general service and agricultural and pumping customers.

utility ratemaking mechanisms.[27] In D.87-05-071, the Commission focused on rules aimed, among other things, at addressing the threat of customers' bypassing the electric utilities' systems in favor of self-generation.[28] Our particular concern, as explained in D.87-05-071, is that a customer with self-generation costs exceeding the utility's short-run marginal costs will bypass the utility system (uneconomic bypass). When this situation occurs, we have found that the customer's self-generation results in "an inefficient allocation of society's resources." (D.87-05-071, at p. 3.)

Included in the policies announced in D.87-05-071 to address the problems created by bypass was our endorsement of utility revenue allocations based on EPMC. We cited the following reasons as support for "embracing EPMC as a guiding principle for revenue allocation" (Id. at p. 5): (1) EPMC provides a fair way of relating each class's revenue requirement to the costs of providing service to that class; (2) EPMC helps reduce inter-class subsidies that distort price signals and thus result in inefficiencies to the detriment of society in general; and (3) EPMC is effective in bringing rates closer to marginal costs in precisely those customer classes most likely to bypass the utility system.

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28 The subject of bypass, to the extent that it affects this proceeding, is discussed in a separate section of this decision.

b. PSD

PSD proposes that a 100% EPMC revenue allocation be adopted, but, like Edison, suggests that the impact of this change in revenue responsibility be mitigated by implementing EPMC over the three-year general rate case cycle. PSD recommends that this end be accomplished by setting an 8% cap above the system average increase for the first year for all customer classes, and by setting the second-year class revenue requirements at the average of the revenue requirements in the first and third years.

PSD acknowledges that under its approach some classes may initially move further from EPMC than they currently are. PSD states that this result occurs due to the cap limiting the increases to some, primarily the domestic class, with the remaining revenue requirement being allocated to the other classes. PSD believes, however, that those customers who would potentially move in the "wrong" direction would also be those who would view investment decisions on a multi-year basis and would be able to view the allocation adjustment on a similar basis. PSD also noted that were the revenue requirement to be significantly higher or lower than the range between Edison's and PSD's proposals, the cap might require adjustment.

With respect to the forum in which the phase-in would be implemented, PSD believes that the ECAC proceeding is the most convenient place for this transition to take place. PSD states that production simulations are already conducted in ECAC, even though on a different year basis than the general rate case. Further, PSD asserts that ECACs are technical proceedings which already involve substantial hearing time, utilize the experts and information necessary to reestimate marginal costs, and currently involve allocation and rate design issues. (See, e.g., D.86-08-083 at 52; D.87-01-051 at 24.) PSD rejects the use of the attrition proceeding which, in PSD's view is intended to be a fairly simple

apparently well-known to the parties in this proceeding who almost unanimously endorsed an allocation of Edison's revenue requirement based on EPMC.[29]

Only one party to this proceeding, ACWA, endorsed a different approach. Specifically, ACWA recommended that class cost responsibility be based on an equal rate of return methodology. As Edison correctly points out this approach is based on the utility's embedded costs, a basis for ratemaking which the Commission has clearly rejected in favor of marginal cost. ACWA's arguments concerning the potential long-term negative impact on certain customer classes of adopting an EPMC revenue allocation could have been more constructively applied to proposals relating to the implementation of EPMC.

We therefore adopt in this proceeding a full EPMC approach for allocating Edison's revenue requirement. Our adoption of this methodology, however, as explained in the succeeding sections, does not end the discussion of revenue allocation. In fact, the use of EPMC requires the Commission to resolve such critical issues as the manner in which it will be implemented and the extent to which it will be applied to all customer classes and to all rate schedules within those classes.

C. <u>Implementation of EPMC Revenue Allocation</u>

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and expeditious proceeding, handled in "cookbook" fashion, which should not get bogged down in major allocation issues.

c. CMA

In CMA's opinion, for an extended period high rates charged to large power customers have shielded other customers from Edison's increasing costs. CMA states that the Commission itself has recognized the need to redress the inequities in the current revenue allocation by moving to EPMC revenue allocations. (D.86-08-083, D.87-05-071.)

CMA acknowledges that principles of rate stability justify a transition period to correct the inequities in the existing revenue allocation. CMA differs, however, as to the time required for this transition and the manner in which such a phase-in should occur. CMA suggests that with PSD's reduced revenue requirement, there is no reason to take three years for the transition. Instead, CMA recommends a two-year transition period using a 13% per year increase in domestic rates.

CMA also endorses a transition to EPMC by capped adjustments and not by reliance on SAPC as suggested by Edison. In CMA's view, the differences between these methods is not in the impact on the domestic customers, but in how quickly the large power customers are relieved of their burden of subsidizing other classes. CMA notes that under the capped increase method, rates for all other classes except GS-1 converge in 1988 upon approximately the same point at about 100% of EPMC. Using Edison's transition method, CMA asserts that major disparities in how the several classes bear the subsidy provided to domestic customers is perpetuated.

With respect to the appropriate forum for making transition adjustments to full EPMC, CMA concurs with the use of the ECAC proceeding as proposed by PSD. In CMA's view, the ECAC proceeding provides greater assurance of expeditious consideration of updated costs. CMA also notes that the continued existence of

Specifically, the adoption of EPMC for Edison as the exclusive basis for revenue allocation, even if implemented over a period of years, will result in a significant rearrangement of revenue responsibility among Edison's customer groups. This impact is in part due to the historic allocation of Edison's revenues on a basis other than EPMC. In Edison's last general rate case, for instance, an allocation formula of a weighted average of 5% EPMC, 95% SAPC, was adopted. (D.84-12-068 at pp. 270-271.)

As a result, Edison's present rates are currently quite far from EPMC. Our move to EPMC could therefore result in significant increases to the domestic class and substantial decreases for the large power class. The Commission must consider if and to what extent these shifts in revenue responsibility should be mitigated in implementing EPMC.

1. Parties Positions

a. Edison

Edison has determined that it is necessary to mitigate the adverse bill impacts on certain customers that would result from an immediate implementation of a full EPMC revenue allocation methodology. To this end, Edison proposes a three-year phase-in plan resulting in a full EPMC revenue allocation by 1990.

Edison's phase-in proposal calls for three annual revenue allocation adjustments. The first of these would take place in the test year 1988 when the total January 1, 1988 revenue requirement, including the revenue requirement adopted in this proceeding, would be allocated on the basis of a weighted average of 2/3 SAPC and 1/3 EPMC. The revenue requirement for 1989 would be allocated on the basis of a weighted average of 1/3 SAPC and 2/3 EPMC, with full EPMC achieved by 1990. In support of its approach, Edison states that its phase-in methodology: (1) treats all customer and rate groups equitably and consistently since they all steadily converge on full EPMC; (2) is understandable and easily applied; and (3) best ensures the achievement of full EPMC within three years.

the attrition rate adjustment proceedings remains at issue in R.86-10-001.

d. IU

IU asserts that two policy considerations require the earliest possible phase-in of full EPMC on the Edison system. These include the spector of further industrial bypass in response to Edison's excessive industrial rates and the relative impact on utility customers of revenue reallocation in the test year versus revenue reallocation in subsequent years. IU states that while a more gradual phase-in may tend to reduce rate shock for some customers, it also postpones rate relief for customers considering uneconomic bypass alternatives. IU also states that the Commission should carefully consider whether postponing rate adjustments to future years will, in fact, reduce rate shock.

With Edison's original revenue request of $302 million, IU proposes a cap of 21% as the maximum initial increase any customer class should receive with a maximum full three-year phase-in. Under PSD's $375 million decrease, IU recommends a 10% cap with a 100% EPMC reallocation to be attained within two rather than three years. Should the revenue requirement fall somewhere between these two recommended levels, IU presented a third revenue allocation option based on the level of Edison's present revenues. Under this scenario, a cap of 13% would apply, and the move to full EPMC would be accomplished in two rather than three years.

IU asks that any revenue allocation update occurring between general rate cases be ministerial in nature and not result in a full-blown recasting of marginal cost concepts, studies, or findings. With respect to procedural forum, IU endorses PSD's recommendation of the ECAC. IU believes that as ECAC has evolved over the years, this type of proceeding offers the most promising time frame and hearing resources for this kind of issue. IU believes that this position is further enhanced by the Commission's forthcoming elimination of the attrition proceedings, a type of

Edison has further proposed that the EPMC phase-in be implemented in the next two Attrition Rate Adjustment (ARA) filings (i.e, 1989 and 1990). Edison supports the use of the ARA proceeding because it is the forum in which a complete update of base rate factors is developed. According to Edison, the ARA is also based on a calendar year which more naturally fits with the forecast process of billing determinants and base rate costs. Edison rejects using the ECAC to implement the phase-in on the grounds that such an approach would unnecessarily complicate the already burdened ECAC proceeding.

With respect to PSD's proposed method of applying "caps" in phasing-in EPMC, Edison states that the adoption of this approach for PG&E in D.86-08-083 is not dispositive of the propriety of applying a similar methodology to Edison. Edison notes the following differences between the PG&E proceeding and the present one: (1) PG&E was requesting a significant decrease in revenues while Edison is requesting an increase, and (2) PG&E's present rate revenues were much closer to EPMC to begin with than are Edison's present rate revenues.

Edison further cites three shortcomings with the PSD approach. First, Edison states that PSD's methodology would result in some rate groups initially moving further away from EPMC. Second, Edison believes that it is unlikely that PSD can achieve its objective of reaching full EPMC by 1990, citing PSD testimony that an increase or decrease beyond a certain range would mean that full EPMC could not be reached using the proposed PSD caps. Third, Edison warns that PSD's proposal to forecast the third year's revenue requirement is an overly complicated process.

Edison also rejects the proposals of other parties, like CMA and FEA, who suggest a more rapid movement to EPMC. Edison believes that any more immediate move to full EPMC will result in severe bill impacts for such customer groups as general service and agricultural and pumping customers.

proceeding the Commission has expressed a great desire to handle in cookbook fashion, quickly with few hearings.

e. FEA

FEA urges this Commission to recognize that movement toward marginal cost-based revenues should be systematic, should present consistent signals to Edison's customers, and should be as rapid as possible. FEA finds numerous problems in this regard with both Edison's and PSD's revenue allocation proposals.

According to FEA, the Edison formula is flawed because it allocates first-year increases to several rate classes that deserve revenue decreases, ignores the need to move classes toward cost in an absolute sense, and fails to produce a systematic or logical pattern of movement toward marginal cost revenue allocation. FEA recommends rejection of PSD's recommended approach on the bases that is not sensitive to the level of revenue increase granted and produces erratic movement toward EPMC revenues.

FEA therefore recommends that the Commission attempt to eliminate at least 50% of existing revenue subsidies in the test year. FEA further recommends that caps should be established to constrain revenue increases and decreases in each step and that the Commission should avoid allocations that do not consistently move toward cost-based revenues. As the amount of revenue requirement found appropriate by the Commission decreases, the FEA also believes that the speed at which classes can be moved to EPMC based revenue allocation should increase.

f. CLECA/CSPG

CLECA/CSPG believe that customer classes such as large power should not and cannot continue to subsidize other customer classes. CLECA/CSPG urge the Commission to demonstrate our commitment to the goal of an EPMC revenue allocation by adopting a fixed implementation schedule in the general rate case. CLECA/CSPG support full implementation effective January 1, 1988.

b. PSD

PSD proposes that a 100% EPMC revenue allocation be adopted, but, like Edison, suggests that the impact of this change in revenue responsibility be mitigated by implementing EPMC over the three-year general rate case cycle. PSD recommends that this end be accomplished by setting an 8% cap above the system average increase for the first year for all customer classes, and by setting the second-year class revenue requirements at the average of the revenue requirements in the first and third years.

PSD acknowledges that under its approach some classes may initially move further from EPMC than they currently are. PSD states that this result occurs due to the cap limiting the increases to some, primarily the domestic class, with the remaining revenue requirement being allocated to the other classes. PSD believes, however, that those customers who would potentially move in the "wrong" direction would also be those who would view investment decisions on a multi-year basis and would be able to view the allocation adjustment on a similar basis. PSD also noted that were the revenue requirement to be significantly higher or lower than the range between Edison's and PSD's proposals, the cap might require adjustment.

With respect to the forum in which the phase-in would be implemented, PSD believes that the ECAC proceeding is the most convenient place for this transition to take place. PSD states that production simulations are already conducted in ECAC, even though on a different year basis than the general rate case. Further, PSD asserts that ECACs are technical proceedings which already involve substantial hearing time, utilize the experts and information necessary to reestimate marginal costs, and currently involve allocation and rate design issues. (See, e.g., D.86-08-083 at 52; D.87-01-051 at 24.) PSD rejects the use of the attrition proceeding which, in PSD's view is intended to be a fairly simple

CLECA/CSPG recognize that while favoring an immediate shift to EPMC revenue allocation, such may not be acceptable to the Commission especially in the event of an increase as proposed by Edison. If there is a phase-in, CLECA/CSPG recommend that it be adopted in only two phases -- January 1, 1988, and January 1, 1989. CLECA/CSPG believe that a longer phase-in will increase the danger of bypass by keeping lower power rates at unnecessarily high levels for a longer period and reducing the credibility of the Commission's commitment to a full EPMC allocation.

CLECA/CSPG also favor a phase-in using a capped EPMC methodology. CLECA/CSPG state that Edison's blend of EPMC/SAPC undermines the commitment to EPMC allocation.

In CLECA/CSPG's view, however, in undertaking a phase-in there should not be any discretion or conditions precluding the attainment of full EPMC by a certain date, even potential rate shock. CLECA/CSPG therefore endorse either the FEA's or IU's phase-in proposals as providing the greatest certainty and appropriate price signals.

Finally, CLECA/CSPG see a danger in linking the phase-in of a full EPMC allocation to ARA cases especially in light of the potential for their elimination. (See D.87-05-071.) However, as long as the ARA continues, CLECA/CSPG state that the escalation factors developed in the ARA could be used in making adjustments to marginal demand and customer costs adopted in the general rate case without relitigating either these costs or the escalation factors. If the ARA ceases to exist, CLECA/CSPG suggest that the escalation factors would have to be adopted in ECAC.

g. <u>TURN</u>

While not addressing revenue allocation in an opening brief, TURN did so in its reply brief filed on August 24, 1987. TURN states that all parties recognize that the movement to full EPMC should be phased-in to avoid rate shock to the residential

and expeditious proceeding, handled in "cookbook" fashion, which should not get bogged down in major allocation issues.

c. CMA

In CMA's opinion, for an extended period high rates charged to large power customers have shielded other customers from Edison's increasing costs. CMA states that the Commission itself has recognized the need to redress the inequities in the current revenue allocation by moving to EPMC revenue allocations. (D.86-08-083, D.87-05-071.)

CMA acknowledges that principles of rate stability justify a transition period to correct the inequities in the existing revenue allocation. CMA differs, however, as to the time required for this transition and the manner in which such a phase-in should occur. CMA suggests that with PSD's reduced revenue requirement, there is no reason to take three years for the transition. Instead, CMA recommends a two-year transition period using a 13% per year increase in domestic rates.

CMA also endorses a transition to EPMC by capped adjustments and not by reliance on SAPC as suggested by Edison. In CMA's view, the differences between these methods is not in the impact on the domestic customers, but in how quickly the large power customers are relieved of their burden of subsidizing other classes. CMA notes that under the capped increase method, rates for all other classes except GS-1 converge in 1988 upon approximately the same point at about 100% of EPMC. Using Edison's transition method, CMA asserts that major disparities in how the several classes bear the subsidy provided to domestic customers is perpetuated.

With respect to the appropriate forum for making transition adjustments to full EPMC, CMA concurs with the use of the ECAC proceeding as proposed by PSD. In CMA's view, the ECAC proceeding provides greater assurance of expeditious consideration of updated costs. CMA also notes that the continued existence of

class. TURN urges the Commission to encourage rate stability and avoid rate shock.

To this end, TURN specifically recommends the adoption of PSD's cap methodology. TURN believes that PSD's revenue allocation is also preferable to all other proposals because it reduces the incentive for large industrial users to seek special contracts and lessens those customers' ability to use the threat of bypass to obtain even greater concessions in future proceedings.

2. Discussion

We have carefully considered the proposals of each of the parties regarding the implementation of an EPMC revenue allocation for Edison. As in the case of the EPMC methodology itself, we note a striking unanimity in the positions which have been taken. Although CMA, IU, FEA, and CLECA/CSPG suggest that an immediate move be made to full EPMC revenue allocation, each has acknowledged the dramatic shift in revenue responsibility which such a change could cause and have suggested various approaches to mitigate that impact. Further, despite their recognition of the possible need to phase-in EPMC, these parties, however, also seek assurance from the Commission, in the form of a fixed schedule of implementation, that the Commission remains firmly committed to EPMC.

The differences between the parties center on the mechanism to be used for mitigating the effects of EPMC, the length of time which should be allowed to phase-in an EPMC revenue allocation, and the forum for implementing that phase-in. With respect to these issues, we again find similarities in the positions of the parties. Except for Edison, all of the other parties favor a capping approach which stays "true" to EPMC rather than an incorporation of SAPC in the phase-in process. The parties' positions also reflect endorsement of a phase-in that is no longer than three years and possibly as short as two years depending on the revenue requirement adopted for Edison in this proceeding. Finally, except for Edison, all other parties believe

the attrition rate adjustment proceedings remains at issue in R.86-10-001.

d. IU

IU asserts that two policy considerations require the earliest possible phase-in of full EPMC on the Edison system. These include the spector of further industrial bypass in response to Edison's excessive industrial rates and the relative impact on utility customers of revenue reallocation in the test year versus revenue reallocation in subsequent years. IU states that while a more gradual phase-in may tend to reduce rate shock for some customers, it also postpones rate relief for customers considering uneconomic bypass alternatives. IU also states that the Commission should carefully consider whether postponing rate adjustments to future years will, in fact, reduce rate shock.

With Edison's original revenue request of $302 million, IU proposes a cap of 21% as the maximum initial increase any customer class should receive with a maximum full three-year phase-in. Under PSD's $375 million decrease, IU recommends a 10% cap with a 100% EPMC reallocation to be attained within two rather than three years. Should the revenue requirement fall somewhere between these two recommended levels, IU presented a third revenue allocation option based on the level of Edison's present revenues. Under this scenario, a cap of 13% would apply, and the move to full EPMC would be accomplished in two rather than three years.

IU asks that any revenue allocation update occurring between general rate cases be ministerial in nature and not result in a full-blown recasting of marginal cost concepts, studies, or findings. With respect to procedural forum, IU endorses PSD's recommendation of the ECAC. IU believes that as ECAC has evolved over the years, this type of proceeding offers the most promising time frame and hearing resources for this kind of issue. IU believes that this position is further enhanced by the Commission's forthcoming elimination of the attrition proceedings, a type of

that it is most appropriate for the phase-in to be implemented in ECAC, as opposed to the ARA (attrition) proceeding.

With these basic positions, we also agree. The need to mitigate the negative effects on certain customer groups caused by the shift to EPMC is even more pronounced for Edison than it was for PG&E. Additionally, unlike PG&E, Edison's current rates are not close to full EPMC, having not been allocated on that basis in the past, and will not be the subject of a significant rate decrease as a result of this proceeding. While we intend to match cost responsibility to the appropriate customer group, we do not intend to cause rate shock to those customer groups (e.g., domestic) who have no options in purchasing or generating electricity other than accepting service from the utility.

We also find that the classes (e.g., large power) who will ultimately benefit most from our adoption of EPMC are also those, as PSD has noted, who are able to make economic decisions, including consideration of revenue allocation adjustments, on a multi-year basis. We believe that our move to EPMC in this case will provide significant enough rate realignments and provide sufficient assurance of our commitment to EPMC that the large power class can properly assess whether bypass of the utility system is economically warranted.

We find that it is therefore reasonable to adopt a phase-in of the full EPMC revenue allocation for Edison. The method which we endorse and has been endorsed by the majority of the parties is a "capping" approach. This approach will permit us to implement a full EPMC methodology while allowing us sufficient flexibility to take into account the need to mitigate any resulting rate shock.

proceeding the Commission has expressed a great desire to handle in cookbook fashion, quickly with few hearings.

e. FEA

FEA urges this Commission to recognize that movement toward marginal cost-based revenues should be systematic, should present consistent signals to Edison's customers, and should be as rapid as possible. FEA finds numerous problems in this regard with both Edison's and PSD's revenue allocation proposals.

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FEA therefore recommends that the Commission attempt to eliminate at least 50% of existing revenue subsidies in the test year. FEA further recommends that caps should be established to constrain revenue increases and decreases in each step and that the Commission should avoid allocations that do not consistently move toward cost-based revenues. As the amount of revenue requirement found appropriate by the Commission decreases, the FEA also believes that the speed at which classes can be moved to EPMC based revenue allocation should increase.

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In determining the most appropriate caps to adopt, we have developed the following table to reflect the impact various revenue allocation approaches would have on rates. This table, based for illustration purposes on a zero-dollar increase, includes revenue allocations (1) proposed in this proceeding, (2) adopted in PG&E, (3) based on full EPMC, (4) based on SAPC, and (5) based on a 5% cap for all classes.

CLECA/CSPG recognize that while favoring an immediate shift to EPMC revenue allocation, such may not be acceptable to the Commission especially in the event of an increase as proposed by Edison. If there is a phase-in, CLECA/CSPG recommend that it be adopted in only two phases -- January 1, 1988, and January 1, 1989. CLECA/CSPG believe that a longer phase-in will increase the danger of bypass by keeping large power rates at unnecessarily high levels for a longer period and reducing the credibility of the Commission's commitment to a full EPMC allocation.

CLECA/CSPG also favor a phase-in using a capped EPMC methodology. CLECA/CSPG state that Edison's blend of EPMC/SAPC undermines the commitment to EPMC allocation.

In CLECA/CSPG's view, however, in undertaking a phase-in there should not be any discretion or conditions precluding the attainment of full EPMC by a certain date, even potential rate shock. CLECA/CSPG therefore endorse either the FEA's or IU's phase-in proposals as providing the greatest certainty and appropriate price signals.

Finally, CLECA/CSPG see a danger in linking the phase-in of a full EPMC allocation to ARA cases especially in light of the potential for their elimination. (See D.87-05-071.) However, as long as the ARA continues, CLECA/CSPG state that the escalation factors developed in the ARA could be used in making adjustments to marginal demand and customer costs adopted in the general rate case without relitigating either these costs or the escalation factors. If the ARA ceases to exist, CLECA/CSPG suggest that the escalation factors would have to be adopted in ECAC.

g. <u>TURN</u>

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SOUTHERN CALIFORNIA EDISON COMPANY
ALTERNATIVE REVENUE ALLOCATION METHODS

CUSTOMER GROUP	(1) SALES (GWH)	(2) PRESENT RATE REV (000's)	SAPC (000's)	(%) INC.	(3) FULL EPMC (000's)	(%) INC.	(SCE) 2/3 SAPC 1/3 EPMC (000's)	(%) INC.	(PSD) GENERAL CAPPED EPMC (000's)	(%) INC.	(PGE) SELECTIVE CAPPED EPMC (000's)	(%) INC.	(REVISED) ALTERNATE CAPPED EPMC (000's)	(%) INC.
DOMESTIC	19,832	1,610,007	1,610,007	0	1,921,571	19	1,713,862	6	1,738,742	8	1,690,466	5	1,690,466	5
SM/MED POWER														
GS-1	3,953	407,611	407,611	0	417,741	2	410,988	1	440,220	8	427,992	5	427,992	5
GS-2	17,846	1,569,264	1,569,264	0	1,472,767	(6)	1,537,098	(2)	1,551,201	(1)	1,583,211	1	1,581,270	1
LARGE POWER														
TOU-8:2ND	6,782	567,362	567,362	0	507,406	(11)	547,377	(4)	534,429	(6)	545,458	(4)	544,789	(4)
TOU-8:PRI	10,406	785,268	785,268	0	677,369	(14)	749,302	(5)	713,445	(9)	728,168	(7)	727,275	(7)
TOU-8:SUB	3,163	196,880	196,880	0	160,147	(19)	184,636	(6)	168,676	(14)	172,157	(13)	171,946	(13)
AGRICULTURE														
PA-1	1,723	144,241	144,241	0	141,961	(2)	143,481	(1)	149,522	4	147,847	2	151,453	5
PA-2	354	28,347	28,347	0	27,198	(4)	27,964	(1)	28,641	1	29,053	2	29,194	3
STREETLIGHTING	471	75,137	75,137	0	57,957	(23)	69,410	(8)	59,240	(21)	59,764	(20)	59,732	(21)
TOTAL	64,529	5,384,117	5,384,117		5,384,117		5,384,117		5,384,117		5,384,117		5,384,117	

REVENUE REQUIREMENT: 5,384,117

(1) September Update.
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(3) Based on Marginal Costs from this decision.

class. TURN urges the Commission to encourage rate stability and avoid rate shock.

To this end, TURN specifically recommends the adoption of PSD's cap methodology. TURN believes that PSD's revenue allocation is also preferable to all other proposals because it reduces the incentive for large industrial users to seek special contracts and lessens those customers' ability to use the threat of bypass to obtain even greater concessions in future proceedings.

2. Discussion

We have carefully considered the proposals of each of the parties regarding the implementation of an EPMC revenue allocation for Edison. As in the case of the EPMC methodology itself, we note a striking unanimity in the positions which have been taken. Although CMA, IU, FEA, and CLECA/CSPG suggest that an immediate move be made to full EPMC revenue allocation, each has acknowledged the dramatic shift in revenue responsibility which such a change could cause and have suggested various approaches to mitigate that impact. Further, despite their recognition of the possible need to phase-in EPMC, these parties, however, also seek assurance from the Commission, in the form of a fixed schedule of implementation, that the Commission remains firmly committed to EPMC.

The differences between the parties center on the mechanism to be used for mitigating the effects of EPMC, the length of time which should be allowed to phase-in an EPMC revenue allocation, and the forum for implementing that phase-in. With respect to these issues, we again find similarities in the positions of the parties. Except for Edison, all of the other parties favor a capping approach which stays "true" to EPMC rather than an incorporation of SAPC in the phase-in process. The parties' positions also reflect endorsement of a phase-in that is no longer than three years and possibly as short as two years depending on the revenue requirement adopted for Edison in this proceeding. Finally, except for Edison, all other parties believe

Based on the record in this proceeding, we find that PSD's approach to phasing-in an EPMC revenue allocation is best matched to our goals. Our only change to that methodology is the adoption of a 5% cap over SAPC, as opposed to 8% cap over SAPC, for all classes in the first year of the three-year phase-in of EPMC. As the preceding table reflects, the impact of adopting a 5% cap on revenue increases results in only a minor change to the decreases resulting to the large power class. We believe therefore that our adoption of a 5% cap over SAPC provides greater relief from rate shock to classes who are negatively affected by our move to EPMC while still providing significant rate reductions for large power customers.

In applying the cap adopted in this proceeding, however, we find no basis in this record for selectively applying different caps to different customer classes. We therefore adopt a single cap (5% over SAPC) to be uniformly applied to all customer classes.

For the two years following the test year, we understand the intent of PSD's recommendation to set the second-year class revenue requirement at the average of the revenue requirements for the first and third years. It is obvious that PSD seeks to ensure, as we do, the attainment of full EPMC at the end of Edison's current rate case cycle (1990). This approach, however, seems nearly impossible to implement due to the complexities of forecasting the utility's third-year revenue requirement in the second year.

We will therefore follow the approach adopted for PG&E. Thus, a cap of 5% over SAPC will be adopted for the test year (1988), but no caps will be adopted in this proceeding for either 1989 or 1990. Instead, we ask the parties to provide such capping proposals, if necessary, on an annual basis, the nature of and forum for which are discussed below. We assure the parties that this finding in no way signals a retreat from EPMC. We intend to achieve full EPMC revenue allocation for Edison by 1990, and this

that it is most appropriate for the phase-in to be implemented in ECAC, as opposed to the ARA (attrition) proceeding.

With these basic positions, we also agree. The need to mitigate the negative effects on certain customer groups caused by the shift to EPMC is even more pronounced for Edison than it was for PG&E. Additionally, unlike PG&E, Edison's current rates are not close to full EPMC, having not been allocated on that basis in the past, and will not be the subject of a significant rate decrease as a result of this proceeding. While we intend to match cost responsibility to the appropriate customer group, we do not intend to cause rate shock to those customer groups (e.g., domestic) who have no options in purchasing or generating electricity other than accepting service from the utility.

We also find that the classes (e.g., large power) who will ultimately benefit most from our adoption of EPMC are also those, as PSD has noted, who are able to make economic decisions, including consideration of revenue allocation adjustments, on a multi-year basis. We believe that our move to EPMC in this case will provide significant enough rate realignments and provide sufficient assurance of our commitment to EPMC that the large power class can properly assess whether bypass of the utility system is economically warranted.

We find that it is therefore reasonable to adopt a phase-in of the full EPMC revenue allocation for Edison. The method which we endorse is a phase-in approach with caps as necessary for individual classes. This approach will permit us to implement a full EPMC methodology while allowing us sufficient flexibility to take into account the need to mitigate any resulting rate shock.

intent should be reflected in any revenue allocation proposed for Edison in 1989 and 1990. We believe, however, that to achieve our goal of full EPMC and ensure rate stability the adopted revenue allocation for the two years following the test year should be based on the circumstances existing at that time.

With respect to the appropriate forum for making the necessary revenue allocation adjustments, we concur with PSD and the majority of the parties that the ECAC proceeding should be used. The initial reason for instituting the 3-R's rulemaking (R.86-10-001) was specifically to consider whether the continuation of the ARA (attrition) proceeding made sense in light of current and expected economic conditions. We found in D.87-05-071 that low inflation and more stable capital costs could lead to relatively small ARA increases over the next few years. Further, the elimination of ARA could foster greater productivity and cost-cutting on the part of the utility. In response to this situation, we considered the complete elimination of ARA. Based on utility concerns that not all growth in demand results in a net increase in revenues (i.e., as resulting from an increase in residential customers), however, we limited the elimination of ARA at this time to the large power class. (D.87-05-0971, at pp. 6-7.)

Our partial elimination of the ARA proceeding coupled with our belief in the benefits to be achieved by its total elimination suggest that this proceeding is not an appropriate forum to implement the three-year phase-in of the EPMC revenue allocation adopted in this proceeding. The uncertainty about the future of this proceeding, as well as its elimination for a significant class, makes the ARA proceeding inappropriate for a process which must take place in the next three years and must consider all class groups. Our decision to use the ECAC proceeding for consideration of revenue allocation issues also mirrors our conclusions in PG&E's most recent general rate case. (See D.86-08-083, at p. 52.)

In determining the most appropriate caps to adopt, we have developed the following table to reflect the impact various revenue allocation approaches would have on rates. This table, based for illustration purposes on a zero-dollar increase, includes revenue allocations (1) proposed in this proceeding, (2) adopted in PG&E, (3) based on full EPMC, (4) based on SAPC, and (5) based on a 5% cap for all classes.

11/18/87

A.86-12-047, I.87-01-017 /ALJ/FSF,SSM/jt

SOUTHERN CALIFORNIA EDISON COMPANY
ALTERNATIVE REVENUE ALLOCATION METHODS

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REVENUE REQUIREMENT: 5,384,117

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With respect to the issues to be heard in ECAC, we share those parties' concerns regarding the complete relitigation of general rate case issues (i.e., marginal cost levels) in ECAC. We find our direction in PG&E's current ECAC proceeding regarding the presentation of revenue allocation and rate design issues in that proceeding to be dispositive. Specifically, in D.87-07-091, we concluded as follows:

> "Our past practice, with some exceptions, is that rate design, revenue allocation, and marginal cost issues should be reviewed in general rate cases and not in ECAC proceedings. However, there are circumstances that justify deviation from that practice here. Moreover, the decision in PG&E's last annual rate case stated that the Commission would allow for changes in the caps on EPMC in future [ECAC] proceedings.
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> * * *
>
> "Accordingly, to provide the Commission with reasonable flexibility, in addition to showings based on SAPC, the record in this phase should include showings based on EPMC for interclass allocations. However, in the interest of not allowing this proceeding to become bogged down in either major policy arguments or the minutia inherent in full-blow rate design proceedings, we will limit EPMC showings ... to adjustment of the caps applied to the EPMC interclass allocation previously adopted." (D.87-07-091, at p. 5.)

We therefore find that Edison's ECAC proceedings for 1989 and 1990 are the appropriate forums for considering for inter-class revenue allocation the necessity, if any, of capping the EPMC revenue allocation for each of those periods and the level of such a cap. As stated in D.87-07-091, the consideration of revenue allocation issues in ECAC, however, does not and should not include relitigation of the marginal cost structure and levels adopted in this proceeding.[31]

For rate changes occurring between this rate case and Edison's 1989 ECAC, we find that the revenue allocation approach (EPMC with a 5% cap over SAPC) adopted in this proceeding should be applied to those intervening rate increases or decreases. Similarly, the revenue allocation approach adopted in Edison's ECAC proceedings for the 1989 and 1990 periods should be applied to Edison's intervening offset filings made after each of these proceedings.

The only exception to this approach will be for minor rate adjustments. In those cases, for ease of administration, we will follow the approach adopted for PG&E in D.86-08-083 and permit Edison to use equal cents per kWh for rate adjustments less than 1%.

D. Inter-Class and Intra-Class Revenue Allocation

In D.86-08-083, the Commission adopted for PG&E an EPMC revenue allocation for both inter-class and intra-class revenue allocation. In this proceeding, the parties' attention largely focused on the inter-class revenue allocation. For intra-class revenue allocation, however, Edison made a separate proposal for small and large light and power customers, and PSD attempted to develop an intra-class revenue allocation for agricultural and pumping customers.

Specifically, for those rate schedules within a rate group for which marginal costs have not been determined in this

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31 We note that Edison and PSD have suggested some minor adjustments to customer and demand charges to reflect changes in the revenue requirement in the period between rate cases. These propriety of such adjustments are discussed in the rate design section of this decision. Our conclusions, however, will be in keeping with our findings above.

Based on the record in this proceeding, we find that a modification of Edison's approach is best matched to our goals. We will adopt an approach that moves each class 1/3 of the way to full EPMC, with a cap of 5% on increases to any class in the first year. Any remaining revenue decreases will be spread to the large power classes in proportion to the deviation of each class from full EPMC. We believe that our adoption of a 5% cap for residential provides adequate relief from rate shock while still providing significant rate reductions for large power customers. Large power customers will see a decrease of greater than 1/3 of the percentage difference between present rates and full EPMC. This faster approach to EPMC will assure large power customers of our commitment to expeditiously achieve full EPMC.

For subsequent years, we will continue phasing-in to full EPMC, mitigating rate shock as required by using caps. We ask the parties to provide such capping proposals, as necessary, on an annual basis, the nature of and forum for which are discussed below. We assure the parties that this finding in no way signals a retreat from EPMC. We intend to achieve full EPMC revenue allocation for Edison as soon as possible, and this intent should be reflected in any revenue allocation proposed for Edison in 1989 and 1990. We believe, however, that to achieve our goal of full EPMC and ensure rate stability the adopted revenue allocation for the two years following the test year should be based on the circumstances existing at that time.

With respect to the appropriate forum for making the necessary revenue allocation adjustments, we concur with PSD and the majority of the parties that the ECAC proceeding should be used. The initial reason for instituting the 3-R's rulemaking (R.86-10-001) was specifically to consider whether the continuation of the ARA (attrition) proceeding made sense in light of current and expected economic conditions. We found in D.87-05-071 that low inflation and more stable capital costs could lead to relatively proceeding (i.e., GS-1, GS-1-APS, GS-1-PG, and TC-1), Edison recommends that the revenue requirement be allocated to rate schedule based on equal percent of present rate revenues.[32] For those rate schedules for which marginal costs have been calculated in this proceeding (i.e., Proposed Schedules TOU-8-SEC, TOU-8-PRI, and TOU-8-SUB), Edison proposes to further allocate the revenue requirement for the customer group to those rate schedules on the basis of full EPMC.

Edison notes that there was no disagreement concerning its proposal and asks that it therefore be adopted. In its brief, CLECA/CSPG has indicated its agreement with Edison that allocation to service voltage sub-classes within the large power classes should be made on a full EPMC basis.

For agricultural and pumping customers, PSD had supported an intra-class revenue allocation for PA-1 and PA-2 and PSD's proposed optional agricultural schedules based on specific customer-incurred costs and use characteristics. As PSD has noted in it brief, the complexity of this effort and the absence of sufficient data, however, prevented PSD from establishing the level of refinement which it sought within the hearing time available. PSD therefore concludes that such a revenue allocation for the agricultural class cannot be undertaken at this time. PSD recommends, however, that Edison be ordered to collect the necessary data on agricultural customers to permit an intra-class revenue allocation for all agricultural rate schedules and options to be accomplished no later than the next general rate case.

We find that Edison's proposal for small light and power intra-class revenue allocation is reasonable in this particular

32 For example, once the GS-1 Rate Group revenue requirement is determined based upon EPMC, that revenue requirement should be allocated to the rate schedules in that rate group on an equal percent of present rate revenues basis.

small ARA increases over the next few years. Further, the elimination of ARA could foster greater productivity and cost-cutting on the part of the utility. In response to this situation, we considered the complete elimination of ARA. Based on utility concerns that not all growth in demand results in a net increase in revenues (i.e., as resulting from an increase in residential customers), however, we limited the elimination of ARA at this time to the large power class. (D.87-05-0971, at pp. 6-7.)

Our partial elimination of the ARA proceeding coupled with our belief in the benefits to be achieved by its total elimination suggest that this proceeding is not an appropriate forum to implement the three-year phase-in of the EPMC revenue allocation adopted in this proceeding. The uncertainty about the future of this proceeding, as well as its elimination for a significant class, makes the ARA proceeding inappropriate for a process which should take place expeditiously and must consider all class groups. Our decision to use the ECAC proceeding for consideration of revenue allocation issues also mirrors our conclusions in PG&E's most recent general rate case. (See D.86-08-083, at p. 52.)

With respect to the issues to be heard in ECAC, we share those parties' concerns regarding the complete relitigation of general rate case issues (i.e., marginal cost levels) in ECAC. We find our direction in PG&E's current ECAC proceeding regarding the presentation of revenue allocation and rate design issues in that proceeding to be dispositive. Specifically, in D.87-07-091, we concluded as follows:

> "Our past practice, with some exceptions, is that rate design, revenue allocation, and marginal cost issues should be reviewed in general rate cases and not in ECAC proceedings. However, there are circumstances that justify deviation from that practice here. Moreover, the decision in PG&E's last annual rate case stated that the Commission would allow for

case. Having no marginal costs calculated for rate schedules within the small light and power group, it would be futile to order an intra-class revenue allocation based on EPMC. An allocation therefore based on equal percent of present rate revenues is an appropriate alternative in this context and should be adopted.

We also find, as PSD has concluded, that our record is insufficient to order a cost-based intra-class revenue allocation for the agricultural rate schedules in this proceeding. We will therefore adopt PSD's proposal, to which Edison has concurred, to allocate any revenue shortfall resulting from the implementation of new agricultural rate options equally among all agricultural rate schedules.

To the extent possible, however, it is our goal to achieve EPMC for all class revenue allocations. To this end, we will adopt the EPMC revenue allocation to rate schedule for the large power class. Further, we will direct Edison to collect the data to develop the marginal costs necessary to achieve an EPMC intra-class revenue allocation for the small light and power and agricultural rate schedules for Edison's next general rate case. With such information in the record of that proceeding, an EPMC revenue allocation can be achieved for both inter-class and intra-class revenue allocation at that time.

E. Street and Area Lighting

The costs imposed on the utility system by streetlight customers fall into two basic categories: a facilities component and an energy component. Traditionally, the revenue requirement for the streetlight group had been excluded from the marginal cost revenue allocation process. In Edison's last general rate case (D.84-12-048), for instance, the Commission had found that the unique combination of operating charcteristics of the streetlight group required their exclusion from the revenue allocation process. These characteristics included non-metered service, uniform load changes in the caps on EPMC in future [ECAC] proceedings.

* * *

"Accordingly, to provide the Commission with reasonable flexibility, in addition to showings based on SAPC, the record in this phase should include showings based on EPMC for interclass allocations. However, in the interest of not allowing this proceeding to become bogged down in either major policy arguments or the minutia inherent in full-blow rate design proceedings, we will limit EPMC showings ... to adjustment of the caps applied to the EPMC interclass allocation previously adopted." (D.87-07-091, at p. 5.)

We therefore find that Edison's ECAC proceedings for 1989 and 1990 are the appropriate forums for considering for inter-class revenue allocation the necessity, if any, of capping the EPMC revenue allocation for each of those periods and the level of such a cap. As stated in D.87-07-091, the consideration of revenue allocation issues in ECAC, however, does not and should not include relitigation of the marginal cost structure and levels adopted in this proceeding.[30]

For rate changes occurring between this rate case and Edison's 1989 ECAC, we find that the rate schedules should be changed by the system average percentage change to maintain the relationships adopted in this proceeding. Similarly, the revenue allocation approach adopted in Edison's ECAC proceedings for the 1989 and 1990 periods should identify the methodology to be applied

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30 We note that Edison and PSD have suggested some minor adjustments to customer and demand charges to reflect changes in the revenue requirement in the period between rate cases. These propriety of such adjustments are discussed in the rate design section of this decision. Our conclusions, however, will be in keeping with our findings above.

shape, utility ownership of the end-use equipment or facilities (streetlights), and low, off-peak energy consumption.

In D.86-08-083, in which we determined PG&E's marginal costs for 1987, the Commission departed from this traditional approach. Specifically, the Commission determined that the energy component of streetlight costs should be included in the revenue allocation process while the facilities charges would continue to be excluded.[33] In doing so, we recognized the uniqueness of the streetlight facility being associated with end-use, but the similarity between streetlight energy charges and energy charges incurred by other customer classes. We determined that, in order to treat all classes equally, the revenue requirement associated with streetlight energy usage should be included in the marginal cost revenue allocation.

Despite this finding, Edison and Cal-SLA maintain in this proceeding that the streetlight group should continue to be excluded in its entirety from our marginal cost revenue allocation. Cal-SLA and Edison both point to the small amount of energy usage by streetlights compared with the energy consumption of other classes. Cal-SLA states that this usage does not justify adopting "the fragmented method" (Cal-SLA Brief, at p. 5) used in PG&E for streetlight revenue allocation. Cal-SLA argues that such an approach furthers no analytical purpose and that exclusion of the energy component from revenue allocation creates no serious revenue shortfall.

Edison similarly relies upon the unique characteristics of streetlights as a basis for continuing their complete exclusion from revenue allocation. Edison disagrees, however, with Cal-SLA

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33 We also found that the exclusion of streetlight facilities would also permit us to unbundle that component of streetlight rates and determine its revenue requirement independently.

to Edison's intervening offset filings made after each of these proceedings if other than SAPC.

The only exception to this approach will be for minor rate adjustments. In those cases, for ease of administration, we will follow the approach adopted for PG&E in D.86-08-083 and permit Edison to use equal cents per kWh for rate adjustments less than 1%.

D. Inter-Class and Intra-Class Revenue Allocation

In D.86-08-083, the Commission adopted for PG&E an EPMC revenue allocation for both inter-class and intra-class revenue allocation. In this proceeding, the parties' attention largely focused on the inter-class revenue allocation. For intra-class revenue allocation, however, Edison made a separate proposal for small and large light and power customers, and PSD attempted to develop an intra-class revenue allocation for agricultural and pumping customers.

Specifically, for those rate schedules within a rate group for which marginal costs have not been determined in this proceeding (i.e., GS-1, GS-1-ABS, GS-1-PG, and TC-1), Edison recommends that the revenue requirement be allocated to rate schedule based on equal percent of present rate revenues.[31] For those rate schedules for which marginal costs have been calculated in this proceeding (i.e., Proposed Schedules TOU-8-SEC, TOU-8-PRI, and TOU-8-SUB), Edison proposes to further allocate the revenue requirement for the customer group to those rate schedules on the basis of full EPMC.

Edison notes that there was no disagreement concerning its proposal and asks that it therefore be adopted. In its brief,

31 For example, once the GS-1 Rate Group revenue requirement is determined based upon EPMC, that revenue requirement should be allocated to the rate schedules in that rate group on an equal percent of present rate revenues basis.

that no serious revenue shortfall will result from such an approach. Edison states that simple logic dictates that if streetlight customers are excluded from the usual revenue allocation process, revenues must then be allocated in some other fashion. In Edison's view, the selection of an alternative method can indeed cause a serious revenue shortfall within the customer group.

PSD urges the Commission to follow its approach used in D.86-08-083. PSD notes that the very purpose of establishing customer classes is to group together customers that have similar characteristics, but are distinct in their characteristics from other groups. Thus, while PSD acknowledges that the streetlight group might have a small amount of level, off-peak energy usage relative to total consumption, this circumstance, according to PSD, does not justify the exclusion of the group in its entirety from the allocation of those revenues required to meet energy needs.

PSD notes, however, that the logic of including streetlight energy charges in the revenue allocation process does not extend to inclusion of the facilities charges in that process. PSD states that facilities charges, unlike streetlight energy charges, bear no relation to the production, transmission, or distribution of electricity and therefore have no relation to a marginal cost revenue allocation.

We find that PSD has correctly interpreted and applied our most recent policy regarding the treatment of streetlight customers in the revenue allocation process. We believe that D.86-08-083 makes clear our decision to exclude only the streetlight facilities charge from this process. As that decision reflects and PSD has indicated, this exclusion is appropriate for a charge which is related to end-use and which is not related to those components which are included in a marginal cost revenue allocation. Despite the low, off-peak energy usage by streetlight customers, it is energy consumption nonetheless and as such is

CLECA/CSPG has indicated its agreement with Edison that allocation to service voltage sub-classes within the large power classes should be made on a full EPMC basis.

For agricultural and pumping customers, PSD had supported an intra-class revenue allocation for PA-1 and PA-2 and PSD's proposed optional agricultural schedules based on specific customer-incurred costs and use characteristics. As PSD has noted in it brief, the complexity of this effort and the absence of sufficient data, however, prevented PSD from establishing the level of refinement which it sought within the hearing time available. PSD therefore concludes that such a revenue allocation for the agricultural class cannot be undertaken at this time. PSD recommends, however, that Edison be ordered to collect the necessary data on agricultural customers to permit an intra-class revenue allocation for all agricultural rate schedules and options to be accomplished no later than the next general rate case.

We find that Edison's proposal for small light and power intra-class revenue allocation is reasonable in this particular case. Having no marginal costs calculated for rate schedules within the small light and power group, it would be futile to order an intra-class revenue allocation based on EPMC. An allocation based on equal percent of present rate revenues is therefore an appropriate alternative in this context and should be adopted. The only exception to this finding is for Schedules TOU-GS and GS-2 for which the revenue allocation should be determined by applying the adopted rates to the billing determinants proposed for those schedules by both Edison and PSD.

We also find, as PSD has concluded, that our record is insufficient to order a cost-based intra-class revenue allocation for the agricultural rate schedules in this proceeding. We will therefore adopt PSD's proposal, to which Edison has concurred, to allocate any revenue shortfall resulting from the implementation of properly included in determining class revenue responsibility. We therefore find reasonable and adopt the continued exclusion of streetlight facilities from the revenue allocation process, but the inclusion in that process of streetlight energy charges.

F. Contract Rate Revenue Deficiencies for Incremental Sales

As we discuss in the Rate Design section of this decision, Edison has proposed two contract rate schedules as a means of mitigating uneconomic bypass. Edison has proposed to allocate the estimated contract rate revenue deficiency of $20 million resulting from one of these rate schedules (TOU-8-C1-1) back to all customer groups and rate schedules on an equal cents per kWh basis.

We have concluded in our section on rate design that the contract rate schedules being proposed by Edison should not be adopted at this time and that issues related to the development of those schedules are properly deferred to the 3-Rs Rulemaking (R.87-10-001). D.87-05-071 in the 3-Rs Rulemaking makes clear that the the policies adopted in that decision are to be implemented in the 3-Rs Rulemaking through the examination and development of guidelines for special contracts, rate options and rate unbundling for different customer classes, and revised forecasts of sales and revenues.

It is therefore unnecessary for any forecasted contract rate revenue deficiency to be allocated to Edison's customers at this time. We also find that while revenue deficiencies are appropriately considered in the revenue allocation process, an estimate of losses which may be incurred to avoid a potential bypass problem is presently too speculative to warrant its adoption at this time. We believe that any issues related to the manner in which this revenue deficiency is to be determined and allocated should first be considered in the same proceeding, R.87-05-071, in new agricultural rate options equally among all agricultural rate schedules.

To the extent possible, however, it is our goal to achieve EPMC for all class revenue allocations. To this end, we will adopt the EPMC revenue allocation to rate schedule for the large power class. Further, we will direct Edison to collect the data to develop the marginal costs necessary to achieve an EPMC intra-class revenue allocation for the small light and power and agricultural rate schedules for Edison's next general rate case. With such information in the record of that proceeding, an EPMC revenue allocation can be achieved for both inter-class and intra-class revenue allocation at that time.

E. Street and Area Lighting

The costs imposed on the utility system by streetlight customers fall into two basic categories: a facilities component and an energy component. Traditionally, the revenue requirement for the streetlight group had been excluded from the marginal cost revenue allocation process. In Edison's last general rate case (D.84-12-048), for instance, the Commission had found that the unique combination of operating charcteristics of the streetlight group required their exclusion from the revenue allocation process. These characteristics included non-metered service, uniform load shape, utility ownership of the end-use equipment or facilities (streetlights), and low, off-peak energy consumption.

In D.86-08-083, in which we determined PG&E's marginal costs for 1987, the Commission departed from this traditional approach. Specifically, the Commission determined that the energy component of streetlight costs should be included in the revenue allocation process while the facilities charges would continue to which the guidelines for special contracts and contract rates are being developed.

G. Adopted Revenue Allocation

The adopted revenue allocation reflected in the following table of this ALJ proposed decision is based on an estimate of the total revenue requirement which will be adopted for Edison as of January 1, 1988. This adopted revenue requirement is currently projected to include revenue changes resulting not only from the decision in this general rate case, but also decisions relating to nuclear decommissioning (OII 86), the SONGS 2 and 3 pre-commercial operation date and post-commercial operation date revenue requirement, amortization of various deferred debit accounts, and refunds for 1987 impacts of the Tax Reform Act of 1986. Present rate revenues reflect the November 1987 rate changes resulting from decisions in Edison's ECAC, AER, ERAM, CLMAC, and Chevron settlement and Uranium contract termination proceedings. (See the attached appendices for revenue detail.)

be excluded.[32] In doing so, we recognized the uniqueness of the streetlight facility being associated with end-use, but the similarity between streetlight energy charges and energy charges incurred by other customer classes. We determined that, in order to treat all classes equally, the revenue requirement associated with streetlight energy usage should be included in the marginal cost revenue allocation.

Despite this finding, Edison and Cal-SLA maintain in this proceeding that the streetlight group should continue to be excluded in its entirety from our marginal cost revenue allocation. Cal-SLA and Edison both point to the small amount of energy usage by streetlights compared with the energy consumption of other classes. Cal-SLA states that this usage does not justify adopting "the fragmented method" (Cal-SLA Brief, at p. 5) used in PG&E for streetlight revenue allocation. Cal-SLA argues that such an approach furthers no analytical purpose and that exclusion of the energy component from revenue allocation creates no serious revenue shortfall.

Edison similarly relies upon the unique characteristics of streetlights as a basis for continuing their complete exclusion from revenue allocation. Edison disagrees, however, with Cal-SLA that no serious revenue shortfall will result from such an approach. Edison states that simple logic dictates that if streetlight customers are excluded from the usual revenue allocation process, revenues must then be allocated in some other fashion. In Edison's view, the selection of an alternative method can indeed cause a serious revenue shortfall within the customer group.

32 We also found that the exclusion of streetlight facilities would also permit us to unbundle that component of streetlight rates and determine its revenue requirement independently.

SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED CAPPED EPMC REVENUE ALLOCATION 1/
EFFECTIVE JANUARY 1, 1988

CUSTOMER GROUP	SALES 2/ (GWH)	PRESENT RATE REV (000's)	TOTAL MC REVS 3/ (000's)	FULL EPMC (000's)	(%) INC.	5% CAPPED EPMC (000's)	(%) INC.	AVERAGE RATE
DOMESTIC	19,832	1,610,007	1,585,305	1,904,623	18	1,675,558	4	0.084
SM/MED POWER								
GS-1	3,953	407,611	344,607	414,055	2	424,215	4	0.107
GS-2	17,846	1,569,264	1,214,938	1,459,772	(7)	1,567,318	(0)	0.088
LARGE POWER								
TOU-8:2ND	6,782	567,362	418,574	502,929	(11)	539,982	(5)	0.080
TOU-8:PRI	10,406	785,268	558,782	671,393	(15)	720,858	(8)	0.069
TOU-8:SUB	3,163	196,880	132,110	158,734	(19)	170,429	(13)	0.054
AGRICULTURE								
PA-1	1,723	144,241	117,108	140,708	(2)	150,117	4	0.087
PA-2	354	28,347	22,455	26,959	(5)	28,957	2	0.082
STREETLIGHTING	471	75,137	53,737	57,744	(23)	59,504	(21)	0.126
TOTAL REVENUE REQUIREMENT	64,529	5,384,117	4,447,617	5,336,917		5,336,917		0.083

1/ Although facilities charges and optional TOU meter charges have been excluded from the revenue allocation process, these amounts have been added to the figures in this table in order to obtain the correct percentage increases and average rate calculations. A breakdown of facilities charges by customer group is given in Appendix F.

2/ Sales figures are taken from the September Update and reflect sales that have not been adjusted for employee discounts.

3/ Based on Marginal Costs as modified by this decision.

PSD urges the Commission to follow its approach used in D.86-08-083. PSD notes that the very purpose of establishing customer classes is to group together customers that have similar characteristics, but are distinct in their characteristics from other groups. Thus, while PSD acknowledges that the streetlight group might have a small amount of level, off-peak energy usage relative to total consumption, this circumstance, according to PSD, does not justify the exclusion of the group in its entirety from the allocation of those revenues required to meet energy needs.

PSD notes, however, that the logic of including streetlight energy charges in the revenue allocation process does not extend to inclusion of the facilities charges in that process. PSD states that facilities charges, unlike streetlight energy charges, bear no relation to the production, transmission, or distribution of electricity and therefore have no relation to a marginal cost revenue allocation.

We find that PSD has correctly interpreted and applied our most recent policy regarding the treatment of streetlight customers in the revenue allocation process. We believe that D.86-08-083 makes clear our decision to exclude only the streetlight facilities charge from this process. As that decision reflects and PSD has indicated, this exclusion is appropriate for a charge which is related to end-use and which is not related to those components which are included in a marginal cost revenue allocation. Despite the low, off-peak energy usage by streetlight customers, it is energy consumption nonetheless and as such is properly included in determining class revenue responsibility. We therefore find reasonable and adopt the continued exclusion of streetlight facilities from the revenue allocation process, but the inclusion in that process of streetlight energy charges.

XI. Rate Design

A. Introduction and General Policy Considerations

In the preceding section, we determined how Edison's adopted revenue requirement would be allocated to customer group and to rate groups within those customer groups (i.e., domestic, small and medium power (GS-1 and GS-2), large power (TOU-8 (Sec), TOU-8 (Prim), and TOU-8 (Subtrans)), agricultural and pumping (PA-1 and PA-2), street and area lighting). We now turn to our final task in this general rate case of determining the specific terms, conditions, and charges under each of Edison's rate schedule included within each customer and rate group.

As in the case of adopting a revenue allocation based on Equal Percent of Marginal Cost (EPMC), our goal in rate design is to achieve rates which reflect the costs which the customer imposes on the system. This approach not only results in an equitable distribution of Edison's revenue requirement, but also provides the most accurate price signals to the customer regarding his energy consumption. To achieve these goals, we must also ensure that rates are structured in a way so that customers can understand and respond appropriately to those signals.

For reasons which similarly supported our phase-in of an EPMC revenue allocation for Edison, however, we also recognize that full implementation of marginal cost-based rates may result in severe bill impacts for some customers. For PG&E, for instance, we recently found it necessary to temporarily limit the impact of certain charges to certain rate groups by imposing rate "limiters" or "caps." In adopting these rate limiters, we sought, however, to still ensure recovery of the revenues allocated to the affected customer group or class and to provide customers whose rates were capped with a clear signal of future bill increases. (D.86-12-091, at pp. 57-59.)

F. Contract Rate Revenue Deficiencies for Incremental Sales

As we discuss in the Rate Design section of this decision, Edison has proposed two contract rate schedules as a means of mitigating uneconomic bypass. Edison has proposed to allocate the estimated contract rate revenue deficiency of $20 million resulting from one of these rate schedules (TOU-8-CR-1) back to all customer groups and rate schedules on an equal cents per kWh basis.

We have concluded in our section on rate design that the generic special contract rate schedule being proposed by Edison (TOU-8-CR-2) should not be adopted at this time and that issues related to the development of that schedule are properly deferred to the 3-Rs Rulemaking (R.87-10-001). D.87-05-071 in the 3-Rs Rulemaking makes clear that the the policies adopted in that decision are to be implemented in the 3-Rs Rulemaking through the examination and development of guidelines for special contracts, rate options and rate unbundling for different customer classes, and revised forecasts of sales and revenues.

We will permit Edison to implement the TOU-8-CR-1 schedule at this time, but will defer any revenue allocation issues to R.87-10-001 as well. It is therefore unnecessary for any forecasted contract rate revenue deficiency to be allocated to Edison's customers at this time. We find that while revenue deficiencies are appropriately considered in the revenue allocation process, an estimate of losses which may be incurred to avoid a potential bypass problem is presently too speculative to warrant its adoption at this time. We believe that any issues related to the manner in which this revenue deficiency is to be determined and allocated should first be considered in the same proceeding, R.87-05-071, in which the guidelines for special contracts and contract rates are being developed.

In D.87-05-071 in the 3-Rs Rulemaking, we have also considered the impact of rate design and special contracts on bypass, the situation in which the customer chooses self-generation over utility service discussed at length in prior sections. Among the policies adopted in D.87-05-071 in the 3-Rs Rulemaking (R.86-10-001) to address the threat of uneconomic bypass was the need for the utility to offer special contracts and rate options to customers in the large power class. We have made clear in D.87-05-071 our intention to consider in the 3-Rs proceeding the guidelines and terms of the special contracts and rate options referenced in that decision along with new forecasts of sales and revenues for the large power class which take into account the regulatory revisions adopted in D.87-05-071.

The rate design principles which are to guide the development of the rate options to be considered in the 3-Rs Rulemaking, however, are also appropriately considered in the rate structures adopted in this proceeding. These principles include the need to "unbundle" rates (the process of pricing each of the various utility services separately) and to differentiate between services and price. This approach, which, as an example, would include the recovery of fixed costs in fixed charge components, offer another means of providing customers with accurate price signals.

Our current rate design philosophy can therefore be summarized as an effort to achieve easily understood, cost-based rates which are designed to recover the customer groups' revenue requirement; to include any terms or conditions necessary to mitigate, to the extent possible and practical, any negative bill impacts; and to reflect a customer's usage patterns and characteristics. This philosophy has largely been mirrored in the rate design recommendations provided in this proceeding not only by Edison and PSD, but by numerous interested parties. These parties include Toward Utility Rate Normalization (TURN), the Western

G. <u>Adopted Revenue Allocation</u>

The adopted revenue allocation shown on the following table of this decision is based on the total revenue requirement adopted for Edison as of January 1, 1988. This adopted revenue requirement includes revenue changes resulting not only from the decision in this general rate case, but also decisions relating to nuclear decommissioning (OII 86), the SONGS 2 and 3 pre-commercial operation date and post-commercial operation date revenue requirement, amortization of various deferred debit accounts, and refunds for 1987 impacts of the Tax Reform Act of 1986. Present rate revenues reflect the November 1987 rate changes resulting from decisions in Edison's ECAC, AER, ERAM, CLMAC, and Chevron settlement and Uranium contract termination proceedings. (See Appendix E and Appendix F for revenue detail.) The adopted ECAC and AER revenues shown in Appendix E include adjustment for fuel savings due to operation of the Balsam Meadow hydroelectric generating plant. Appendix E shows no revenue change because by coincidence the fuel savings decrease is exactly offset by increases due to adopted changes in franchise fee and uncollectible factors.

Mobilehome Association (WMA), recreational vehicle (RV) park owners, the Schools Committee to Reduce Utility Bills (SCRUB), the California Large Energy Consumers Association and the California Steel Producers Group (CLECA/CSPG), the Federal Executive Agencies (FEA), the Industrial Users (IU), the California Manufacturers Association (CMA), the State Department of General Services (DGS), the Cogenerators of Southern California (CSC), the Association of California Water Agencies (ACWA), and the California City-County Street Light Association (CAL-SLA).

Before proceeding to those specific recommendations, we note, for Edison's benefit, that we appreciate the differences in operations and customers between Edison and PG&E. Edison has asserted this fact as a reason why the rate design approved for PG&E may not be suitable for Edison. Our reliance on decisions relating to PG&E's adopted rate design is, however, appropriate as a means of identifying current Commission rate design policy; determining whether that policy is to be continued, modified, or abandoned; and ensuring, to the extent possible, consistent treatment of all ratepayers.

Finally, Edison and PSD urge that the Commission recognize in reviewing their recommendations that their jointly and separate proposed rate structures were based on the assumption that ERAM would continue through the test year 1988. Because the Commission has recently eliminated ERAM for large light and power customers in D.87-05-071, Edison wishes to reserve the right to make needed modifications, if any, to its rate design through the further proceeding provided by D.87-05-071 in R.86-10-001. Our review of that decision above makes clear that the Commission does intend to review in R.86-10-001 rate options and special contracts offered to the large power group. To the extent provided by that rulemaking, Edison and PSD are, of course, entitled to participate and make rate design recommendations.

SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED PHASE-IN SCALED REVENUE ALLOCATION 1\
EFFECTIVE JANUARY 1, 1988

CUSTOMER GROUP	SALES 2/ (GWH)	PRESENT RATE REV (000's)	TOTAL MC REVS 3/ (000's)	FULL EPMC (000's)	(%) INC.	PHASE-IN SCALED (000's)	(%) INC.	AVERAGE RATE
DOMESTIC	19,832	1,610,007	1,584,484	1,909,515	18.60	1,689,171	4.92	0.085
SM/MED POWER								
GS-1	3,953	407,611	344,607	415,238	1.87	410,153	0.62	0.104
GS-2	17,846	1,569,264	1,214,887	1,463,922	(6.71)	1,534,150	(2.24)	0.086
LARGE POWER								
TOU-8:2ND	6,782	567,362	418,574	504,365	(11.10)	546,088	(3.75)	0.081
TOU-8:PRI	10,406	785,268	558,782	673,311	(14.26)	747,596	(4.80)	0.072
TOU-8:SUB	3,163	196,880	132,110	159,188	(19.14)	183,841	(6.62)	0.058
AGRICULTURE	2,077	172,588	139,455	168,103	(2.60)	171,093	(0.87)	0.082
STREETLIGHTING	471	75,137	19,882	57,812	(23.06)	69,362	(7.69)	0.147
TOTAL REVENUE REQUIREMENT	64,529	5,384,117	4,412,782	5,351,454		5,351,454		0.083

1/ Although facilities charges and optional TOU meter charges have been excluded from the revenue allocation process, these amounts have been added to the figures in this table in order to obtain the correct percentage increases and average rate calculations. A breakdown of facilities charges by customer group is given in Appendix F.

2/ Sales figures are taken from the September Update and reflect sales that have not been adjusted for employee discounts.

3/ Based on Marginal Costs from Exhibit 41 as modified by this decision.

B. Domestic Customer Group

In this proceeding, Edison and PSD reached agreement on almost all of the components of the rate design for the domestic customer group. Issues, however, remain for these two parties with respect to the development of the optional time-of-use rate schedule (TOU-D) and the appropriate submetering discount to be applied to the master-meter schedules for mobilehome parks (DMS-2).

TURN, WMA, and the RV park owners also presented positions on several issues related to residential rate design. TURN focused on Edison's and PSD's recommendation to eliminate the minimum bill, while WMA and the RV park owners addressed the discount and charges provided under the DMS-2 schedule and the applicability of that schedule or a new, similar schedule to RV park owners.

1. Baseline

Edison and PSD are in agreement on the quantities to allow for baseline. Specifically, Edison and PSD have agreed that for all customers, except all-electric customers and residents in Zone 15 of the CEC's climatic regions, baseline allowances should be set at the mid-point of the range allowed by Public Utilities Code section 739 (55 percent of average aggregate use). For all-electric customers other than those residing in Zone 15, the parties have agreed that the baseline allowance should be set at the maximum allowed under the statutory range (60 percent of average aggregate usage for summer and 70 percent of average aggregate usage for winter). Edison and PSD also agree that all usage at and below the baseline allocation should be priced at 85 percent of the system average rate, the maximum charge allowed by law. (Cal.Pub.Util. Code, Section 739).

For Zone 15, the high desert area of the Coachella Valley, Edison and PSD have agreed to an adjustment of the seasonal allocation of the baseline allowances similar to that adopted in Edison's last general rate case (D.84-12-068). In that case, the

XI. Rate Design

A. Introduction and General Policy Considerations

In the preceding section, we determined how Edison's adopted revenue requirement would be allocated to customer group and to rate groups within those customer groups (i.e., domestic, small and medium power (GS-1 and GS-2), large power (TOU-8 (Sec), TOU-8 (Prim), and TOU-8 (Subtrans)), agricultural and pumping (PA-1 and PA-2), street and area lighting). We now turn to our final task in this general rate case of determining the specific terms, conditions, and charges under each of Edison's rate schedule included within each customer and rate group.

As in the case of adopting a revenue allocation based on Equal Percent of Marginal Cost (EPMC), our goal in rate design is to achieve rates which reflect the costs which the customer imposes on the system. This approach not only results in an equitable distribution of Edison's revenue requirement, but also provides the most accurate price signals to the customer regarding his energy consumption. To achieve these goals, we must also ensure that rates are structured in a way so that customers can understand and respond appropriately to those signals.

For reasons which similarly supported our phase-in of an EPMC revenue allocation for Edison, however, we also recognize that full implementation of marginal cost-based rates may result in severe bill impacts for some customers. For PG&E, for instance, we recently found it necessary to temporarily limit the impact of certain charges to certain rate groups by imposing rate "limiters" or "caps." In adopting these rate limiters, we sought, however, to still ensure recovery of the revenues allocated to the affected customer group or class and to provide customers whose rates were capped with a clear signal of future bill increases. (D.86-12-091, at pp. 57-59.)

Commission had determined that the total annual baseline allowance for Zone 15 should be no more than that established under the normal formula. However, the Commission concluded that the allocation of that allowance to season should be modified to allow a greater allowance during the summer months when the Zone 15 area experiences extreme heat. (D. 84-12-068, at pp. 292-296.) As of June 1987, this allowance was 1,200 kWh per month for the summer.

In this proceeding, Edison had orginally proposed that baseline quantities for customers residing in Zone 15 be established under the same methodology as that applied to the other CEC zones. Subsequent to making this proposal, however, Edison was asked by the Coachella Valley Association of Governments (CVAG) to reconsider its position and provide baseline quantities for Zone 15 based on the Commission's methodology adopted in Edison's last general rate case. In response to that request, Edison proposed a summer baseline quantity of 1,200 kWh per month with the winter baseline quantities set such that the total annual baseline allowance for Zone 15 would be the same as Edison had originally proposed. This proposal, with which PSD agreed, is considered by both parties not to have a material impact on customers outside of Zone 15.

Edison and PSD also agree that for master-metered Schedules DMS-1 and DMS-2 (applicable to submetered multifamily and mobilehome domestic customers) the baseline quantities should be the same as for other domestic and comparable non-master-metered customers. Edison and PSD also agree that baseline quantities for Schedule DM, master-metered multifamily domestic customers without submetering, should be reduced in proportion to the lower average use of customers on this schedule.

We find that Edison and PSD have applied the appropriate methodologies in calculating the baseline allowances for all zones and for all domestic rate schedules. We also find reasonable the allocation adjustment for Zone 15 customers in recognition of the

In D.87-05-071 in the 3-Rs Rulemaking, we have also considered the impact of rate design and special contracts on bypass, the situation in which the customer chooses self-generation over utility service discussed at length in prior sections. Among the policies adopted in D.87-05-071 in the 3-Rs Rulemaking (R.86-10-001) to address the threat of uneconomic bypass was the need for the utility to offer special contracts and rate options to customers in the large power class. We have made clear in D.87-05-071 our intention to consider in the 3-Rs proceeding the guidelines and terms of the special contracts and rate options referenced in that decision along with new forecasts of sales and revenues for the large power class which take into account the regulatory revisions adopted in D.87-05-071.

The rate design principles which are to guide the development of the rate options to be considered in the 3-Rs Rulemaking, however, are also appropriately considered in the rate structures adopted in this proceeding. These principles include the need to "unbundle" rates (the process of pricing each of the various utility services separately) and to differentiate between services and price. This approach, which, as an example, would include the recovery of fixed costs in fixed charge components, offer another means of providing customers with accurate price signals.

Our current rate design philosophy can therefore be summarized as an effort to achieve easily understood, cost-based rates which are designed to recover the customer groups' revenue requirement; to include any terms or conditions necessary to mitigate, to the extent possible and practical, any negative bill impacts; and to reflect a customer's usage patterns and characteristics. This philosophy has largely been mirrored in the rate design recommendations provided in this proceeding not only by Edison and PSD, but by numerous interested parties. These parties include Toward Utility Rate Normalization (TURN), the Western

extreme heat in that region during the summer and the absence of any material impact on other customers. These baseline quantities for Zone 15 should also be based on the 4-month summer/8-month winter periods adopted for this zone in Edison's last general rate case. (D.84-12-068, at p. 296.) We therefore find that the following daily baseline quantities are reasonable for Schedules D, DMS-1, and DMS-2 and should be adopted with implementation effective as of the next seasonal change. The baseline quantities, adopted for the DM schedule are included in an appendix to this decision.

Baseline Allowances
Schedule Nos. D, DMS-1, and DMS-2

Monthly Baseline kWh Allowances:

Line No.	Baseline Region (1)	Summer Basic (2)	Summer All-Electric (3)	Winter Basic (4)	Winter All-Electric (5)
1.	10	252	302	259	493
2.	13	441	800	321	1,072
3.	14	363	532	292	855
4.	15	1,200	1,200	330	670
5.	16	250	445	279	1,035
6.	17	333	425	278	615

Adopted Daily Baseline kWh Allowances:

Line No.	Baseline Region (1)	Summer Basic (2)	Summer All-Electric (3)	Winter Basic (4)	Winter All-Electric (5)
1.	10	8.2	9.8	8.6	16.3
2.	13	14.4	26.1	10.6	35.5
3.	14	11.8	17.3	9.7	28.3
4.	15	39.3	39.3	10.9	22.1
5.	16	8.2	14.5	9.2	34.3
6.	17	10.9	13.9	9.2	20.4

2. Domestic Time-of-Use

Edison proposes two new schedules for the domestic customer group: a seasonal option (Schedule DS) and a time of use option (Schedule TOU-D). Edison states that it has proposed these

Mobilehome Association (WMA), recreational vehicle (RV) park owners, the Schools Committee to Reduce Utility Bills (SCRUB), the California Large Energy Consumers Association and the California Steel Producers Group (CLECA/CSPG), the Federal Executive Agencies (FEA), the Industrial Users (IU), the California Manufacturers Association (CMA), the State Department of General Services (DGS), the Cogenerators of Southern California (CSC), the Association of California Water Agencies (ACWA), and the California City-County Street Light Association (CAL-SLA).

Before proceeding to those specific recommendations, we note, for Edison's benefit, that we appreciate the differences in operations and customers between Edison and PG&E. Edison has asserted this fact as a reason why the rate design approved for PG&E may not be suitable for Edison. Our reliance on decisions relating to PG&E's adopted rate design is, however, appropriate as a means of identifying current Commission rate design policy; determining whether that policy is to be continued, modified, or abandoned; and ensuring, to the extent possible, consistent treatment of all ratepayers.

Finally, Edison and PSD urge that the Commission recognize in reviewing their recommendations that their jointly and separate proposed rate structures were based on the assumption that ERAM would continue through the test year 1988. Because the Commission has recently eliminated ERAM for large light and power customers in D.87-05-071, Edison wishes to reserve the right to make needed modifications, if any, to its rate design through the further proceeding provided by D.87-05-071 in R.86-10-001. Our review of that decision above makes clear that the Commission does intend to review in R.86-10-001 rate options and special contracts offered to the large power group. To the extent provided by that rulemaking, Edison and PSD are, of course, entitled to participate and make rate design recommendations.

options to help mitigate the negative impacts on domestic customers of increased rates and changed allocation procedures and to provide these customers with more control over their electric bills.

For its proposed optional Schedule TOU-D, Edison established a ten cents-per-kilowatt-hour premium for incremental summer on-peak energy and a five cents-per-kilowatt-hour discount for incremental off-peak energy. For the seasonal Schedule DS, Edison similarly charges a premium on all summer month kilowatt-hours in excess of average winter month usage and a discount on winter month kilowatt-hours in excess of average summer month usage.

PSD also recommends the use of rate options for the domestic customer group. PSD accepts Edison's proposed seasonal option, Schedule DS. Additionally, the two parties have reached an agreement to open the optional time-of-use program to all customers, but with a limit of 10,000 new meters per year. The parties have similarly agreed that Edison should target the marketing of the program primarily to its largest customers. Edison and PSD also concur that the seasonal option should be limited to customers with an established billing history of one year and an average monthly usage in excess of 1,200 kWh seasonal option (Schedule DS). The parties agree that the expected revenue shortfall, which both parties find will have no significant impact on the nonparticipant, should be included in the domestic customer group revenue requirement.

PSD differs with Edison, however, on the rate structure which should be adopted for the optional TOU schedule. In contrast to Edison's "premium/discount" approach, PSD recommends a conventional TOU rate structure requiring a three-tiered rate structure with all three time differentiated charges based on marginal costs. PSD also recommends that a floor be established for the TOU-D bill equal to the customer's usage times the off-peak energy rate. According to PSD, this approach is necessary to

B. Domestic Customer Group

In this proceeding, Edison and PSD reached agreement on almost all of the components of the rate design for the domestic customer group. Issues, however, remain for these two parties with respect to the development of the optional time-of-use rate schedule (TOU-D) and the appropriate submetering discount to be applied to the master-meter schedules for mobilehome parks (DMS-2).

TURN, WMA, and the RV park owners also presented positions on several issues related to residential rate design. TURN focused on Edison's and PSD's recommendation to eliminate the minimum bill, while WMA and the RV park owners addressed the discount and charges provided under the DMS-2 schedule and the applicability of that schedule or a new, similar schedule to RV park owners.

1. Baseline

Edison and PSD are in agreement on the quantities to allow for baseline. Specifically, Edison and PSD have agreed that for all customers, except all-electric customers and residents in Zone 15 of the CEC's climatic regions, baseline allowances should be set at the mid-point of the range allowed by Public Utilities Code section 739 (55 percent of average aggregate use). For all-electric customers other than those residing in Zone 15, the parties have agreed that the baseline allowance should be set at the maximum allowed under the statutory range (60 percent of average aggregate usage for summer and 70 percent of average aggregate usage for winter). Edison and PSD also agree that all usage at and below the baseline allocation should be priced at 85 percent of the system average rate, the maximum charge allowed by law. (Cal.Pub.Util. Code, Section 739).

For Zone 15, the high desert area of the Coachella Valley, Edison and PSD have agreed to an adjustment of the seasonal allocation of the baseline allowances similar to that adopted in Edison's last general rate case (D.84-12-068). In that case, the

eliminate the possibility, even though unlikely, that a customer could have a negative bill resulting from the interaction of exclusively off-peak usage and baseline allowances.

The positions of Edison and PSD regarding the appropriate rate structure for the optional TOU-D rate schedule are summarized below. Our resolution of this issue and our findings on the DS proposal and the proposed limitations on both rate options follow that summary.

a. TOU-D Rate Schedule

According to Edison, its seasonal and TOU options for residential customers are designed to complement each other. Edison states that the seasonal option provides those customers who have low summer season usage a reduced rate without the need for a time-of-use meter. The TOU option, according to Edison, is directed to customers who can shift their daily usage to the off-peak period and will benefit from a time-of-use meter. Edison believes that the complementary nature of these two options depends on the premium/discount feature as a common link to permit customers to understand and compare the two options. Edison asserts that by using the premium/discount approach, the customer can readily assess the cost of using energy in the on-peak period and the savings to be realized by shifting use to the off-peak period.

Edison believes that the simplicity and ease of comprehension achieved by its rate option proposals is critical. According to Edison, while its TOU-D option may be chosen by only one out of ten customers, Edison believes that it is obligated to clearly communicate the options to all qualifying customers to permit them to make an informed decision.

With respect to the rate established by Edison for the TOU-D schedule, Edison states that an optional rate must be set below average cost in order to be desirable. The level below average cost, according to Edison, is a matter of judgment based on

Commission had determined that the total annual baseline allowance for Zone 15 should be no more than that established under the normal formula. However, the Commission concluded that the allocation of that allowance to season should be modified to allow a greater allowance during the summer months when the Zone 15 area experiences extreme heat. (D. 84-12-068, at pp. 292-296.) As of June 1987, this allowance was 1,200 kWh per month for the summer.

In this proceeding, Edison had originally proposed that baseline quantities for customers residing in Zone 15 be established under the same methodology as that applied to the other CEC zones. Subsequent to making this proposal, however, Edison was asked by the Coachella Valley Association of Governments (CVAG) to reconsider its position and provide baseline quantities for Zone 15 based on the Commission's methodology adopted in Edison's last general rate case. In response to that request, Edison proposed a summer baseline quantity of 1,200 kWh per month with the winter baseline quantities set such that the total annual baseline allowance for Zone 15 would be the same as Edison had originally proposed. This proposal, with which PSD agreed, is considered by both parties not to have a material impact on customers outside of Zone 15.

Edison and PSD also agree that for master-metered Schedules DMS-1 and DMS-2 (applicable to submetered multifamily and mobilehome domestic customers) the baseline quantities should be the same as for other domestic and comparable non-master-metered customers. Edison and PSD also agree that baseline quantities for Schedule DM, master-metered multifamily domestic customers without submetering, should be reduced in proportion to the lower average use of customers on this schedule.

We find that Edison and PSD have applied the appropriate methodologies in calculating the baseline allowances for all zones and for all domestic rate schedules. We also find reasonable the allocation adjustment for Zone 15 customers in recognition of the

weighing the need to attract the customer against the need to mitigate the amount of revenue shortfall. With these principles in mind, Edison established its optional rates approximately halfway between average and marginal costs. Edison states that under this rate structure the customer receives approximately half the difference between the average and marginal cost in the off-peak period in the form of a discount and pays approximately half the difference in the form of a premium in the summer on-peak period.

Edison believes that PSD's proposed three-tier TOU-D rate is unduly complicated and will not achieve the goal of attracting customers. Edison states that PSD has placed too much emphasis on the need to mirror marginal cost in the rate design and too little concern on the need for simplicity of design and comprehension by the customer.

PSD characterizes the dispute between itself and Edison over the appropriate rate structure for the optional TOU-D schedule as a contrast between short term simplicity and long term accuracy. PSD notes that the basis for the Edison proposal is to provide a simple way for the average residential customer to readily compute the costs they incur by using on- and off-peak energy, irrespective of what the base charge may be. PSD asserts, however, that Edison has acknowledged that the similarity of Edison's proposed rates to marginal cost-based rates is merely a coincidence.

PSD asserts that its proposed TOU-D rate structure is preferable to Edison's since it can not only be understood by customers, but also provides more accurate price signals with rates based on time-differentiated marginal costs. PSD believes that any customer signing up for a TOU schedule understands that he will pay more for on-peak usage and less for off-peak usage, a differential which will be seen in a simple review of his bill. In PSD's opinion, the Edison approach will only make for simpler computation if the customer knows his instantaneous usage.

extreme heat in that region during the summer and the absence of any material impact on other customers. These baseline quantities for Zone 15 should also be based on the 4-month summer/8-month winter periods adopted for this zone in Edison's last general rate case. (D.84-12-068, at p. 296.) We therefore find that the following daily baseline quantities are reasonable for Schedules D, DMS-1, DMS-2, DAPS-2, DE, and D-PG, and should be adopted with implementation effective as of the next seasonal change. The baseline quantities, adopted for the DM schedule are included in an appendix to this decision.

Baseline Allowances
Schedule Nos. D, DMS-1, DMS-2, DAPS-2, DE, and D-PG

Monthly Baseline kWh Allowances:

Line No.	Baseline Region (1)	Summer Basic (2)	Summer All-Electric (3)	Winter Basic (4)	Winter All-Electric (5)
1.	10	252	302	259	493
2.	13	441	800	321	1,072
3.	14	363	532	292	855
4.	15	1,200	1,200	330	670
5.	16	250	445	279	1,035
6.	17	333	425	278	615

Adopted Daily Baseline kWh Allowances:

Line No.	Baseline Region (1)	Summer Basic (2)	Summer All-Electric (3)	Winter Basic (4)	Winter All-Electric (5)
1.	10	8.2	9.8	8.6	16.3
2.	13	14.4	26.1	10.6	35.5
3.	14	11.8	17.3	9.7	28.3
4.	15	39.3	39.3	10.9	22.1
5.	16	8.2	14.5	9.2	34.3
6.	17	10.9	13.9	9.2	20.4

2. Domestic Time-of-Use

Edison proposes two new schedules for the domestic customer group: a seasonal option (Schedule DS) and a time of use option (Schedule TOU-D). Edison states that it has proposed these

PSD states that Edison has not made clear what steps it would take when the recommended discounts become further estranged from marginal cost relationships. PSD asserts that the proper function of TOU rates is to reflect costs imposed on the system, a goal achieved, according to PSD, only by PSD's recommended TOU-D structure.

b. Adopted Schedules

If the goal of offering optional rates to residential customers is to permit these customers to understand the impact of their energy usage and to control that usage, we believe that such a goal can only be achieved by offering the most accurate price signals. As we have stated repeatedly in this decision, these signals result from relying on marginal cost-based rates.

We have also endorsed, however, the need to achieve simplicity in rate design in order to enhance the customer's understanding of his bill. This goal, as Edison has recognized, is particularly important in developing a new rate option and attracting customers to the schedule.

We do not believe, however, in this case, that the goal of simplicity in rate design outweighs the need for cost-based rates. For an option schedule aimed at providing the customer with truly cost-based rates, the primary emphasis should be on the relation of the charge to the cost imposed by the customer on the system.

We find that PSD's proposed three-tier rate design achieves the goal of cost-based rates for the TOU-D schedule. We further agree with PSD that its approach is not so overly complicated that the customer will not be able to understand the changes in his consumption patterns which will be required to lower his bill. We also share PSD's concern that in the future the differential between Edison's marginal costs and its proposed discount, which is not significant at this time, might increase and

options to help mitigate the negative impacts on domestic customers of increased rates and changed allocation procedures and to provide these customers with more control over their electric bills.

For its proposed optional Schedule TOU-D, Edison established a ten cents-per-kilowatt-hour premium for incremental summer on-peak energy and a five cents-per-kilowatt-hour discount for incremental off-peak energy. For the seasonal Schedule DS, Edison similarly charges a premium on all summer month kilowatt-hours in excess of average winter month usage and a discount on winter month kilowatt-hours in excess of average summer month usage.

PSD also recommends the use of rate options for the domestic customer group. PSD accepts Edison's proposed seasonal option, Schedule DS. Additionally, the two parties have reached an agreement to open the optional time-of-use program to all customers, but with a limit of 10,000 new meters per year. The parties have similarly agreed that Edison should target the marketing of the program primarily to its largest customers. Edison and PSD also concur that the seasonal option should be limited to customers with an established billing history of one year and an average monthly usage in excess of 1,200 kWh seasonal option (Schedule DS). The parties agree that the expected revenue shortfall, which both parties find will have no significant impact on the nonparticipant, should be included in the domestic customer group revenue requirement.

PSD differs with Edison, however, on the rate structure which should be adopted for the optional TOU schedule. In contrast to Edison's "premium/discount" approach, PSD recommends a conventional TOU rate structure requiring a three-tiered rate structure with all three time differentiated charges based on marginal costs. PSD also recommends that a floor be established for the TOU-D bill equal to the customer's usage times the off-peak energy rate. According to PSD, this approach is necessary to

thereby move the proposed rates further from marginal costs and the very purpose of the schedule.

We therefore find that PSD's proposed TOU-D schedule is reasonable and should be adopted in this proceeding. We note that the TOU-D schedule is designed as an option. Should Edison encounter significant difficulties in communicating the availability of the TOU-D schedule or its impact, Edison can use that experience as a basis for offering a different rate structure in its next general rate case.

We also find reasonable the DS schedule and the limitations placed on the availability of the DS and TOU-D schedule to which Edison and PSD have agreed. The adoption of these recommendations and both optional schedules will provide to an appropriate level of residential customers significant options for controlling their energy usage and reducing their electric bills.

3. <u>Minimum Bill and Customer Charges</u>

Under Edison's current domestic rate schedule, Edison provides for a minimum bill under which customers pay a certain amount each month even if their usage is less than that represented by the minimum bill. In this proceeding, Edison and PSD have recommended that the existing minimum bill or charge, which accrues on a daily basis, be replaced by a customer charge of 15 cents per day or $4.65 a month. This proposal was opposed by TURN.

a. <u>Parties Positions</u>

In this proceeding, Edison and PSD have agreed that the existing minimum charge should be replaced by a daily customer charge. According to Edison and PSD, the charge will reflect in rates administrative costs associated with reading the meter and billing the account and a portion of the fixed distribution costs associated with providing service to the customer. The parties believe that this charge is therefore consistent with the process of unbundling rates and sending clearer price signals.

eliminate the possibility, even though unlikely, that a customer could have a negative bill resulting from the interaction of exclusively off-peak usage and baseline allowances.

The positions of Edison and PSD regarding the appropriate rate structure for the optional TOU-D rate schedule are summarized below. Our resolution of this issue and our findings on the DS proposal and the proposed limitations on both rate options follow that summary.

a. TOU-D Rate Schedule

According to Edison, its seasonal and TOU options for residential customers are designed to complement each other. Edison states that the seasonal option provides those customers who have low summer season usage a reduced rate without the need for a time-of-use meter. The TOU option, according to Edison, is directed to customers who can shift their daily usage to the off-peak period and will benefit from a time-of-use meter. Edison believes that the complementary nature of these two options depends on the premium/discount feature as a common link to permit customers to understand and compare the two options. Edison asserts that by using the premium/discount approach, the customer can readily assess the cost of using energy in the on-peak period and the savings to be realized by shifting use to the off-peak period.

Edison believes that the simplicity and ease of comprehension achieved by its rate option proposals is critical. According to Edison, while its TOU-D option may be chosen by only one out of ten customers, Edison believes that it is obligated to clearly communicate the options to all qualifying customers to permit them to make an informed decision.

With respect to the rate established by Edison for the TOU-D schedule, Edison states that an optional rate must be set below average cost in order to be desirable. The level below average cost, according to Edison, is a matter of judgment based on

Edison and PSD agree that the customer charge should be $4.65 per month based on a daily charge of 15 cents, less than a one cent difference from the figure derived by PSD based on marginal customer costs. The parties further agree that the proposed customer charge revenue should be deducted from the baseline revenue requirement when determining the baseline rate.

Both parties also agree that the function of the customer charge is to reflect marginal customer costs. While the proposed customer charge collects only a portion of Edison's marginal customer costs, Edison and PSD assert that their proposed customer charge will still achieve the objective of recovering a larger portion of fixed costs through the fixed component of the rate.

PSD acknowledges that some ratepayers may experience bill increases, but that this result is not solely from the imposition of a customer charge. Rather, PSD states that such increases result in the significant increase in revenue requirement responsibility of the domestic class due to the inclusion of marginal customer costs in revenue allocation and the move toward an EPMC revenue allocation for Edison.

TURN opposes replacing the current minimum bill with a customer charge. TURN states that under a minimum bill consumers pay a certain minimum amount even if their usage is so low that they would otherwise be billed less than the minimum amount. In contrast, according to TURN, a customer charge is a charge paid by all consumers in addition to the amount they are billed for the electricity they use. TURN notes that most consumers are not directly affected by the minimum bill because they use more than the minimum bill amount.

TURN states that similar proposals to replace the minimum bill with a customer charge have been rejected in recent SDG&E and PG&E rate proceedings. TURN notes that in both cases the Commission refused to adopt customer charges for reasons of

weighing the need to attract the customer against the need to mitigate the amount of revenue shortfall. With these principles in mind, Edison established its optional rates approximately halfway between average and marginal costs. Edison states that under this rate structure the customer receives approximately half the difference between the average and marginal cost in the off-peak period in the form of a discount and pays approximately half the difference in the form of a premium in the summer on-peak period.

Edison believes that PSD's proposed three-tier TOU-D rate is unduly complicated and will not achieve the goal of attracting customers. Edison states that PSD has placed too much emphasis on the need to mirror marginal cost in the rate design and too little concern on the need for simplicity of design and comprehension by the customer.

PSD characterizes the dispute between itself and Edison over the appropriate rate structure for the optional TOU-D schedule as a contrast between short term simplicity and long term accuracy. PSD notes that the basis for the Edison proposal is to provide a simple way for the average residential customer to readily compute the costs they incur by using on- and off-peak energy, irrespective of what the base charge may be. PSD asserts, however, that Edison has acknowledged that the similarity of Edison's proposed rates to marginal cost-based rates is merely a coincidence.

PSD asserts that its proposed TOU-D rate structure is preferable to Edison's since it can not only be understood by customers, but also provides more accurate price signals with rates based on time-differentiated marginal costs. PSD believes that any customer signing up for a TOU schedule understands that he will pay more for on-peak usage and less for off-peak usage, a differential which will be seen in a simple review of his bill. In PSD's opinion, the Edison approach will only make for simpler computation if the customer knows his instantaneous usage.

fairness and economic efficiency. (Citing, D.85-12-068, at p. 97; D.86-12-091, at pp. 25-26.)

TURN believes that this same reasoning is applicable to this proceeding. TURN asserts that the application of the customer charge results in penalizing customers living in certain regions and overcharging small users and that the charge itself is improperly based on the cost of connecting new customers. The totality of the effect of imposing the customer charge, in TURN's opinion, is therefore to create inefficiencies and waste in energy consumption by sending the wrong price signals to customers encouraging greater consumption and consumption in summer periods.

TURN further argues that almost 74% of Edison's residential customers would receive increased rates solely from the imposition of a customer charge. TURN states that the customer charge also improperly results in the greatest rate increase to customers in temperate zones who generally impose lower costs on the system. TURN further asserts that PSD's testimony demonstrated that the smallest users, many of whom are low-income, will receive the largest percentage increase from the proposed customer charge. According to TURN, Edison and PSD have inappropriately based customer charges on incremental customer costs when decremental customer costs more closely reflect the actual customer cost imposed on the system.

b. <u>Discussion</u>

In our decision adopting the rate design for PG&E's most recent test year (D.86-12-091), we supported in principle PSD's recommendation to establish a customer charge for residential customers. However, because of the constraints which baseline placed on the establishment of Tier I and Tier II rates, we found that a customer charge would distort these rates, thus obscuring its intended purpose. The customer charge was therefore rejected in favor of a minimum charge which was found to allow residential customers to pay a share of fixed costs and to better understand

PSD states that Edison has not made clear what steps it would take when the recommended discounts become further estranged from marginal cost relationships. PSD asserts that the proper function of TOU rates is to reflect costs imposed on the system, a goal achieved, according to PSD, only by PSD's recommended TOU-D structure.

b. Adopted Schedules

If the goal of offering optional rates to residential customers is to permit these customers to understand the impact of their energy usage and to control that usage, we believe that such a goal can only be achieved by offering the most accurate price signals. As we have stated repeatedly in this decision, these signals result from relying on marginal cost-based rates.

We have also endorsed, however, the need to achieve simplicity in rate design in order to enhance the customer's understanding of his bill. This goal, as Edison has recognized, is particularly important in developing a new rate option and attracting customers to the schedule.

We do not believe, however, in this case, that the goal of simplicity in rate design outweighs the need for cost-based rates. For an option schedule aimed at providing the customer with truly cost-based rates, the primary emphasis should be on the relation of the charge to the cost imposed by the customer on the system.

We find that PSD's proposed three-tier rate design achieves the goal of cost-based rates for the TOU-D schedule. We further agree with PSD that its approach is not so overly complicated that the customer will not be able to understand the changes in his consumption patterns which will be required to lower his bill. We also share PSD's concern that in the future the differential between Edison's marginal costs and its proposed discount, which is not significant at this time, might increase and

their rates. The minimum charge was adopted for both domestic TOU and domestic non-TOU customers. (D.86-12-091, at pp. 25-26, 30.)

In this proceeding, we similarly find supportable the principle of the customer charge. We agree with Edison's and PSD's reasoning that such a charge, based on marginal customer costs, would provide more accurate price signals to the domestic customer class regarding their usage.

We must, however, also consider the impact of such a proposal on all domestic customers. PSD has recognized that the Edison customer, following this proceeding, must face increased revenue responsibility related to the combined impact of the inclusion of marginal customer costs in the revenue allocation process and the move toward an EPMC inter-class revenue allocation. The impact of these changes on residential customers seems significant enough without a change in rate structure which will shift fixed charges into a single component. TURN has demonstrated that the effect of this change would be to impose a disproportionate increase on the smallest users.

As in the PG&E case, we are also concerned with the interaction of the customer charge with baseline rates. As shown by TURN, this interaction would result in increasing rates to certain temperate zone customers disproportionate with the costs which they impose on Edison's system.

Finally, as our section in this decision on marginal customer costs reflect, we have found that PSD's methodology for calculating those costs failed to take into consideration decremental customer costs. We adopted PSD's approach at this time, with certain modifications, only as a proxy for the approved incremental/decremental approach. While the customer charge is appropriately based on marginal customer costs, we share TURN's concern that the estimate used by PSD failed to take into consideration decremental customer costs which should have been part of that calculation.

thereby move the proposed rates further from marginal costs and the very purpose of the schedule.

We therefore find that PSD's proposed TOU-D schedule is reasonable and should be adopted in this proceeding. The estimated revenue deficiency from TOU-D should be allocated to all residential customers. We note that the TOU-D schedule is designed as an option. Should Edison encounter significant difficulties in communicating the availability of the TOU-D schedule or its impact, Edison can use that experience as a basis for offering a different rate structure in its next general rate case. Due to the complexities of the schedule, Edison should, however, have a reasonable period of time to implement the new schedule, but should offer the tariff no later than June 1, 1988.

We also find reasonable the DS schedule and the limitations placed on the availability of the DS and TOU-D schedule to which Edison and PSD have agreed. The adoption of these recommendations and both optional schedules will provide to an appropriate level of residential customers significant options for controlling their energy usage and reducing their electric bills.

3. Minimum Bill and Customer Charges

Under Edison's current domestic rate schedule, Edison provides for a minimum bill under which customers pay a certain amount each month even if their usage is less than that represented by the minimum bill. In this proceeding, Edison and PSD have recommended that the existing minimum bill or charge, which accrues on a daily basis, be replaced by a customer charge of 15 cents per day or $4.65 a month. This proposal was opposed by TURN.

a. Parties Positions

In this proceeding, Edison and PSD have agreed that the existing minimum charge should be replaced by a daily customer charge. According to Edison and PSD, the charge will reflect in rates administrative costs associated with reading the meter and billing the account and a portion of the fixed distribution costs associated with providing service to the customer. The parties

For these reasons, we adopt TURN's recommendation to continue the minimum charge at this time. PSD and Edison may renew their request in Edison's next general rate case at which time the calculations of marginal customer costs should be based on the proper methodology and our move to EPMC revenue allocation should be completed. These changes could be significant factors in determining the propriety of adopting a customer charge at that time.

4. <u>DM, DMS-1, and DMS-2 Schedules</u>

Under master-metered Schedules DMS-1 and DMS-2, Edison provides a monthly discount to multifamily accommodations and to mobilehome park owners who provide submetering service to their tenants. The discount mobilehome park owners are provided under the DMS-2 schedule stems from the statutory requirement (Public Utilities Code Section 739.5) that each utility provide a sufficient differential in the rate charged to mobilehome park owners to allow recovery of the reasonable average cost to such customer for providing a submetered service to individual mobilehome residents. The DMS-2 schedule also includes baseline allowances, which along with the submetered discount, were developed by the Commission after extensive hearings in Case Nos. 9988 and 10273 pursuant to Sections 739 and 739.5 of the Public Utilities Code. The present discount under the DMS-2 schedule is $.23 per space per day which equals $6.90 per space per month.

At issue in this proceeding is not only the calculation of the DMS-2 discount, but the need to adjust that discount to recognize a diversity benefit and the applicability of the DMS-2 schedule itself or the creation of a new, similar schedule for RV park owners. These issues have been the focus of the testimony and briefs of Edison, WMA, and the RV park owners. Edison's recommended discount for DMS-1 and the diversity factors to be applied to that discount and to charges under Schedule DM were not opposed by any party.

believe that this charge is therefore consistent with the process of unbundling rates and sending clearer price signals.

Edison and PSD agree that the customer charge should be $4.65 per month based on a daily charge of 15 cents, less than a one cent difference from the figure derived by PSD based on marginal customer costs. The parties further agree that the proposed customer charge revenue should be deducted from the baseline revenue requirement when determining the baseline rate.

Both parties also agree that the function of the customer charge is to reflect marginal customer costs. While the proposed customer charge collects only a portion of Edison's marginal customer costs, Edison and PSD assert that their proposed customer charge will still achieve the objective of recovering a larger portion of fixed costs through the fixed component of the rate.

PSD acknowledges that some ratepayers may experience bill increases, but that this result is not solely from the imposition of a customer charge. Rather, PSD states that such increases result in the significant increase in revenue requirement responsibility of the domestic class due to the inclusion of marginal customer costs in revenue allocation and the move toward an EPMC revenue allocation for Edison.

TURN opposes replacing the current minimum bill with a customer charge. TURN states that under a minimum bill consumers pay a certain minimum amount even if their usage is so low that they would otherwise be billed less than the minimum amount. In contrast, according to TURN, a customer charge is a charge paid by all consumers in addition to the amount they are billed for the electricity they use. TURN notes that most consumers are not directly affected by the minimum bill because they use more than the minimum bill amount.

TURN states that similar proposals to replace the minimum bill with a customer charge have been rejected in recent SDG&E and PG&E rate proceedings. TURN notes that in both cases the

With respect to the calculation of the DMS-2 discount, following the filing of WMA's prepared testimony, Edison acceded to several of WMA's recommended changes to Edison's calculation and increased its originally recommended discount of approximately $5.10 per space per month to $6.88 per space per month. Edison did not concur, however, with WMA's proposed allowance for distribution energy losses nor the need to use a levelized fixed charge rate in that calculation. WMA's proposed discount, which includes an allowance for distribution energy losses of $2.94 per space per month, yields a total recommended discount of $10.76 per space per month.

PSD's recommended discount was similar to that originally proposed by Edison. Specifically, PSD had found, based on Edison's original cost study, that submetering costs were $5.14 per month. PSD's recommended discount, however, was $.64 per month due to the inclusion in its calculation of a deduction for the customer charge of $4.36 per month. Such an adjustment of the submetered discount, however, is no longer necessary given our rejection of PSD's and Edison's proposal to initiate customer charges for the domestic customer group.

The need to adjust the discount to recognize a diversity benefit was first recognized by the Commission in our consideration of PG&E's rate design for its most recent test year. In D.86-12-091 in that proceeding, we found that a diversity benefit existed when a master metered customer had more sales billed at baseline rates and less at nonbaseline rates than were actually used by his submetered customers. While PG&E and WMA disagreed in that case regarding the use of diversity factors and the method of their calculation, we concluded that an adjustment of the discount was required to correct an inequity in the billing of submetered mobile homes. For this reason, we adopted PG&E's diversity factors "as the best available quantification of diversity benefits." (D.86-12-091, at p. 35.) In response to WMA's concerns regarding

Commission refused to adopt customer charges for reasons of fairness and economic efficiency. (Citing, D.85-12-068, at p. 97; D.86-12-091, at pp. 25-26.)

TURN believes that this same reasoning is applicable to this proceeding. TURN asserts that the application of the customer charge results in penalizing customers living in certain regions and overcharging small users and that the charge itself is improperly based on the cost of connecting new customers. The totality of the effect of imposing the customer charge, in TURN's opinion, is therefore to create inefficiencies and waste in energy consumption by sending the wrong price signals to customers encouraging greater consumption and consumption in summer periods.

TURN further argues that almost 74% of Edison's residential customers would receive increased rates solely from the imposition of a customer charge. TURN states that the customer charge also improperly results in the greatest rate increase to customers in temperate zones who generally impose lower costs on the system. TURN further asserts that PSD's testimony demonstrated that the smallest users, many of whom are low-income, will receive the largest percentage increase from the proposed customer charge. According to TURN, Edison and PSD have inappropriately based customer charges on incremental customer costs when decremental customer costs more closely reflect the actual customer cost imposed on the system.

b. <u>Discussion</u>

In our decision adopting the rate design for PG&E's most recent test year (D.86-12-091), we supported in principle PSD's recommendation to establish a customer charge for residential customers. However, because of the constraints which baseline placed on the establishment of Tier I and Tier II rates, we found that a customer charge would distort these rates, thus obscuring its intended purpose. The customer charge was therefore rejected in favor of a minimum charge which was found to allow residential the accuracy of PG&E's diversity factors, however, we directed PG&E in the future to base its diversity factors on the usage patterns of mobilehome parks individually metered by PG&E. (Id.)

In this proceeding, Edison did not initially recommend a diversity adjustment of the DMS-2 discount. Only after Edison had submitted its cost study supporting its discount and interested party testimony had been filed did Edison determine that such an adjustment was appropriate not only for the DMS-2 schedule, but also for the DMS-1 and DM schedules. Because of WMA's objection to the lateness of this proposal, the presiding ALJ, with the concurrence of the parties, concluded that hearings on this issue would be deferred to September, 1987, with prepared testimony being filed in advance of that date. On September 22, 1987, testimony was presented by Edison and WMA with concurrent briefs filed on this issue on September 30, 1987. PSD offered no testimony on this issue and did not propose a discount adjusted to reflect a diversity benefit.

a. <u>Allowance for Distribution Energy Losses</u>

For PG&E's most recent test year, WMA had recommended that line losses from the master meter to the submeter be considered in calculating the master meter discount. While we agreed in principle with WMA, we did not adopt WMA's line loss estimate since it was based on PG&E's entire distribution system and might not be applicable to mobilehome parks. We also found that WMA's approach was further flawed by the failure to consider the amount of distribution wire required to serve the typical submetered customer and by the estimate increasing the existing discount by nearly 40%. We directed PG&E, however, to conduct a study with WMA to determine the actual line losses of submetered mobilehome parks and to present the results of that study in PG&E's next general rate case proceeding. (D.86-12-091, at pp. 36-37.)

In this proceeding, WMA again seeks to include an allowance for distribution energy losses. WMA asserts that customers to pay a share of fixed costs and to better understand their rates. The minimum charge was adopted for both domestic TOU and domestic non-TOU customers. (D.86-12-091, at pp. 25-26, 30.)

In this proceeding, we similarly find supportable the principle of the customer charge. We agree with Edison's and PSD's reasoning that such a charge, based on marginal customer costs, would provide more accurate price signals to the domestic customer class regarding their usage.

We must, however, also consider the impact of such a proposal on all domestic customers. PSD has recognized that the Edison customer, following this proceeding, must face increased revenue responsibility related to the combined impact of the inclusion of marginal customer costs in the revenue allocation process and the move toward an EPMC inter-class revenue allocation. The impact of these changes on residential customers seems significant enough without a change in rate structure which will shift fixed charges into a single component. TURN has demonstrated that the effect of this change would be to impose a disproportionate increase on the smallest users.

As in the PG&E case, we are also concerned with the interaction of the customer charge with baseline rates. As shown by TURN, this interaction would result in increasing rates to certain temperate zone customers disproportionate with the costs which they impose on Edison's system.

Finally, as our section in this decision on marginal customer costs reflect, we have found that PSD's methodology for calculating those costs failed to take into consideration decremental customer costs. We adopted PSD's approach at this time, with certain modifications, only as a proxy for the approved incremental/decremental approach. While the customer charge is appropriately based on marginal customer costs, we share TURN's concern that the estimate used by PSD failed to take into

Edison's 1987 cost study of electric service in mobilehome parks is flawed for its failure to account for these losses which WMA states that even Edison admits do occur within mobilehome parks. WMA testified that an appropriate loss percentage was 8.02% which is based on an analysis of Edison's losses from the primary distribution level to the residential distribution system. Based on this figure, WMA calculated the cost of losses at an average of $2.94 per space per month, an amount which was added to WMA's initially calculated discount of $7.82 per space per month to yield the total recommended discount of $10.76 per space per month.

WMA also believes that a special loss study would not be cost effective for either Edison or DMS-2 customers and therefore recommends against the Commission ordering such a study in this case. If one is required, the WMA recommends that its 8.02% discount be adopted and that a balancing account be established to record the amount paid DMS-2 customers for losses. After the study is concluded, WMA suggests that any adjustment to the discount based on under-payments or over-payment be included in establishing the discount in Edison's next general rate case. WMA believes this approach is needed to ensure that mobilehome park owners do not wait another three years to receive an allowance for costs which the owners admittedly incur.

WMA states that its position in this proceeding is distinguishable from that which it asserted in the PG&E proceeding. Specifically, WMA notes that its current recommendation is not based on Edison's entire distribution system and includes a balancing account proposal. WMA also asserts that since losses are a small percentage of all of the kilowatt-hours used by each resident, the cost is therefore a small percentage of each resident's total bill and its impact on the discount should be irrelevant.

Edison challenges the WMA's inclusion of an allowance for distribution energy losses on the following grounds: (1) it is not consideration decremental customer costs which should have been part of that calculation.

For these reasons, we adopt TURN's recommendation and continue the minimum base rate charge at $0.10/day. PSD and Edison may renew their request in Edison's next general rate case at which time the calculations of marginal customer costs should be based on the proper methodology and our move to EPMC revenue allocation should be completed. These changes could be significant factors in determining the propriety of adopting a customer charge at that time.

4. DM, DMS-1, and DMS-2 Schedules

Under master-metered Schedules DMS-1 and DMS-2, Edison provides a monthly discount to multifamily accommodations and to mobilehome park owners who provide submetering service to their tenants. The discount mobilehome park owners are provided under the DMS-2 schedule stems from the statutory requirement (Public Utilities Code Section 739.5) that each utility provide a sufficient differential in the rate charged to mobilehome park owners to allow recovery of the reasonable average cost to such customer for providing a submetered service to individual mobilehome residents. The DMS-2 schedule also includes baseline allowances, which along with the submetered discount, were developed by the Commission after extensive hearings in Case Nos. 9988 and 10273 pursuant to Sections 739 and 739.5 of the Public Utilities Code. The present discount under the DMS-2 schedule is $.23 per space per day which equals $6.90 per space per month.

At issue in this proceeding is not only the calculation of the DMS-2 discount, but the need to adjust that discount to recognize a diversity benefit and the applicability of the DMS-2 schedule itself or the creation of a new, similar schedule for RV park owners. These issues have been the focus of the testimony and briefs of Edison, WMA, and the RV park owners. Edison's recommended discount for DMS-1 and the diversity factors to be based on a loss study, (2) it is based on Edison's entire distribution system and therefore may not in many instances be applicable to mobilehome parks, (3) it increases the discount of over 40% from the currently authorized discount, and (4) it fails to recognize that the typical mobilehome park owners are compensated for Edison system losses through the domestic tariff. In Edison's view, the absence of a study and WMA's reliance on Edison's entire distribution system renders WMA's adjustment an uneducated guess unrelated to the losses specifically incurred by mobilehomes.

Edison also rejects WMA's suggested balancing account. Edison believes that such a proposal would be administratively burdensome and contrary to Commission policy to limit the use of balancing accounts to address major issues affecting all of Edison's customers.

In this proceeding, WMA has obviously attempted to refine its method of estimating the distribution energy losses incurred by mobilehome parks after first proposing such an allowance for PG&E. Despite this effort, we still find WMA's proposed approach to be flawed. WMA again has considered the general level of losses at the primary and secondary distribution levels, which although experienced in some part by mobilehome parks, the exact level is unknown. We, in fact, know of no way in which that level can be properly determined without a line loss study. In this proceeding, however, WMA indicates that such a study is not cost-effective for Edison's ratepayers or even DMS-2 customers and should not be undertaken.

In the absence of a line loss study, WMA asks that the Commission implement a balancing account for mobilehome park customers. We note, as Edison has, that balancing accounts have been reserved for major proceedings affecting all utility customers. We find unwarranted therefore the imposition of this administrative burden for a single cost related to a specific applied to that discount and to charges under Schedule DM were not opposed by any party.

With respect to the calculation of the DMS-2 discount, following the filing of WMA's prepared testimony, Edison acceded to several of WMA's recommended changes to Edison's calculation and increased its originally recommended discount of approximately \$5.10 per space per month to \$6.88 per space per month. Edison did not concur, however, with WMA's proposed allowance for distribution energy losses nor the need to use a levelized fixed charge rate in that calculation. WMA's proposed discount, which includes an allowance for distribution energy losses of \$2.94 per space per month, yields a total recommended discount of \$10.76 per space per month.

PSD's recommended discount was similar to that originally proposed by Edison. Specifically, PSD had found, based on Edison's original cost study, that submetering costs were \$5.14 per month. PSD's recommended discount, however, was \$.64 per month due to the inclusion in its calculation of a deduction for the customer charge of \$4.36 per month. Such an adjustment of the submetered discount, however, is no longer necessary given our rejection of PSD's and Edison's proposal to initiate customer charges for the domestic customer group.

The need to adjust the discount to recognize a diversity benefit was first recognized by the Commission in our consideration of PG&E's rate design for its most recent test year. In D.86-12-091 in that proceeding, we found that a diversity benefit existed when a master metered customer had more sales billed at baseline rates and less at nonbaseline rates than were actually used by his submetered customers. While PG&E and WMA disagreed in that case regarding the use of diversity factors and the method of their calculation, we concluded that an adjustment of the discount was required to correct an inequity in the billing of submetered mobile homes. For this reason, we adopted PG&E's diversity factors customer group, the representative of which does not even support the very study needed to identify the existence and extent of the costs in question.

With respect to WMA's assertion that losses represent a small portion of overall bills, we note that our focus is on the discount for which WMA's allowance for distribution energy losses would represent a significant portion. The magnitude of the increase in the discount caused by an allowance for distribution energy losses requires even more that the Commission be assured of the accuracy of the estimate on which that allowance is based.

For the foregoing reasons, the Commission will not adopt WMA's estimate of distribution energy losses nor will we provide for an allowance for those losses in the DMS-2 discount at this time. The only remaining issue is whether Edison should be required, as PG&E was, to conduct a study to analyze the existence and extent of these losses. It is WMA's position that no study should be conducted due to its lack of cost-effectiveness. We find it difficult to believe that WMA intended that position to result, as we have found, in distribution energy losses never being included in the DMS-2 discount. We also are reluctant to resolve this issue in this manner, especially with the acknowledgment that mobilehome park owners do incur distribution energy losses.

We therefore find reasonable the undertaking by Edison of a study to determine the actual line losses of submetered mobilehome parks to ensure that the costs associated with those losses are properly reflected in the DMS-2 discount. Due to questions regarding the study's cost-effectiveness, however, we further find reasonable that the costs of the study should be spread equally to the beneficiaries of that study -- all submetered mobilehome park owners served by Edison under the DMS-2 schedule.

b. Fixed Rate Charges

In a departure from its approach in previous years, Edison has proposed in this proceeding to use a nonlevelized, as "as the best available quantification of diversity benefits." (D.86-12-091, at p. 35.) In response to WMA's concerns regarding the accuracy of PG&E's diversity factors, however, we directed PG&E in the future to base its diversity factors on the usage patterns of mobilehome parks individually metered by PG&E. (Id.)

In this proceeding, Edison did not initially recommend a diversity adjustment of the DMS-2 discount. Only after Edison had submitted its cost study supporting its discount and interested party testimony had been filed did Edison determine that such an adjustment was appropriate not only for the DMS-2 schedule, but also for the DMS-1 and DM schedules. Because of WMA's objection to the lateness of this proposal, the presiding ALJ, with the concurrence of the parties, concluded that hearings on this issue would be deferred to September, 1987, with prepared testimony being filed in advance of that date. On September 22, 1987, testimony was presented by Edison and WMA with concurrent briefs filed on this issue on September 30, 1987. PSD offered no testimony on this issue and did not propose a discount adjusted to reflect a diversity benefit.

a. Allowance for Distribution Energy Losses

For PG&E's most recent test year, WMA had recommended that line losses from the master meter to the submeter be considered in calculating the master meter discount. While we agreed in principle with WMA, we did not adopt WMA's line loss estimate since it was based on PG&E's entire distribution system and might not be applicable to mobilehome parks. We also found that WMA's approach was further flawed by the failure to consider the amount of distribution wire required to serve the typical submetered customer and by the estimate increasing the existing discount by nearly 40%. We directed PG&E, however, to conduct a study with WMA to determine the actual line losses of submetered mobilehome parks and to present the results of that study in PG&E's next general rate case proceeding. (D.86-12-091, at pp. 36-37.)

opposed to a levelized, fixed charge rate in determining the mobilehome park discount. Edison states that this change is based on its interpretation of the applicable code section, California Public Utilities Code Section 739.5. Edison states that Section 739.5 provides that the discount cannot exceed Edison's average cost that it "would have incurred in providing comparable service directly to the users of the service." According to Edison, the use of a levelized fixed charge rate in calculating the discount for the test year (1988) would result in the discount exceeding Edison's average cost of service. Edison asserts that this average cost can only be produced by using the nonlevelized fixed charge rate.

WMA objects to Edison's use of the nonlevelized fixed charge rate to calculate the DMS-2 discount in this proceeding. According to WMA, the fixed charge rate, which is used to compute the total annual cost of capital investment, has the same value for all of the years during the useful life of the asset when it is levelized. A nonlevelized fixed charge rate, in contrast, changes value for each year of useful life to reflect changes in return, taxes, and book value. WMA states that, based on this distinction between the two rates, the nonlevelized fixed charge rate is higher than the levelized fixed charge rate in the early years and lower in the later years of the useful life.

WMA asserts that because Edison relied on levelized fixed charge rates in the earlier years of the discount, it will have understated the costs in those years should it now be permitted to change to a nonlevelized fixed charge rate. The DMS-2 customer, in WMA's opinion, is therefore deprived of the full cost of the assets by this change in accounting methodology. To make this change, WMA also believes that Edison should have first determined a true need for doing so and then, if the change were warranted, ensure that its figures were adjusted to make up for the earlier deficit.

In this proceeding, WMA again seeks to include an allowance for distribution energy losses. WMA asserts that Edison's 1987 cost study of electric service in mobilehome parks is flawed for its failure to account for these losses which WMA states that even Edison admits do occur within mobilehome parks. WMA testified that an appropriate loss percentage was 8.02% which is based on an analysis of Edison's losses from the primary distribution level to the residential distribution system. Based on this figure, WMA calculated the cost of losses at an average of $2.94 per space per month, an amount which was added to WMA's initially calculated discount of $7.82 per space per month to yield the total recommended discount of $10.76 per space per month.

WMA also believes that a special loss study may not be cost effective for either Edison or DMS-2 customers. If one is required, the WMA recommends that its 8.02% discount be adopted and that a balancing account be established to record the amount paid DMS-2 customers for losses. After the study is concluded, WMA suggests that any adjustment to the discount based on under-payments or over-payment be included in establishing the discount in Edison's next general rate case. WMA believes this approach is needed to ensure that mobilehome park owners do not wait another three years to receive an allowance for costs which the owners admittedly incur.

WMA states that its position in this proceeding is distinguishable from that which it asserted in the PG&E proceeding. Specifically, WMA notes that its current recommendation is not based on Edison's entire distribution system and includes a balancing account proposal. WMA also asserts that since losses are a small percentage of all of the kilowatt-hours used by each resident, the cost is therefore a small percentage of each resident's total bill and its impact on the discount should be irrelevant.

WMA contends that Edison's use of the nonlevelized fixed charge rate is inappropriate for these additional reasons: (1) Edison's interpretation of Section 739.5, as requiring this change, is "highly technical"; (2) the change will require complex accounting adjustments, a result disputed by Edison; and (3) the change will bring instability to the discount amount. WMA also asserts that, even if a nonlevelized fixed charge rate were used, Edison's calculation is flawed as it fails to identify the true average fixed charge rates for all assets in each account. For all of these reasons, WMA urges that, in the absence of a line loss allocation, the DMS-2 discount be fixed at $7.82 per space per month based on the application of the levelized fixed charge rates.

We share WMA's concern with Edison's decision to switch from using a levelized to a nonlevelized fixed charge rate in calculating the DMS-2 discount. We find that Edison's reliance on its interpretation of Section 739.5 alone is not sufficient to warrant a change which could have serious economic repercussions for the affected customer group. The distinction between levelized and nonlevelized fixed charge rates makes inquiry into the impact of using the levelized fixed charge rates for many years and switching now to a fixed charge rate critical to our approval of that change. In order to make the change, we therefore need to know specifically whether the levelized fixed charge rate did in fact represent Edison's average costs in prior years; the extent to which those costs were under-stated or over-stated, if at all, by using a levelized fixed charge rate; and the extent to which it fails to represent Edison's average cost now.

We also find it unlikely that the Legislature intended that, for purposes of determining the mobilehome park discount, the utility's average costs were to be developed in isolation for each test year without regard to the manner in which those costs had been determined in prior years. Certainly, enough flexibility was intended under the statute to recognize the possibility that

Edison challenges the WMA's inclusion of an allowance for distribution energy losses on the following grounds: (1) it is not based on a loss study, (2) it is based on Edison's entire distribution system and therefore may not in many instances be applicable to mobilehome parks, (3) it increases the discount of over 40% from the currently authorized discount, and (4) it fails to recognize that the typical mobilehome park owners are compensated for Edison system losses through the domestic tariff. In Edison's view, the absence of a study and WMA's reliance on Edison's entire distribution system renders WMA's adjustment an uneducated guess unrelated to the losses specifically incurred by mobilehomes.

Edison also rejects WMA's suggested balancing account. Edison believes that such a proposal would be administratively burdensome and contrary to Commission policy to limit the use of balancing accounts to address major issues affecting all of Edison's customers.

In this proceeding, WMA has obviously attempted to refine its method of estimating the distribution energy losses incurred by mobilehome parks after first proposing such an allowance for PG&E. Despite this effort, we still find WMA's proposed approach to be flawed. WMA again has considered the general level of losses at the primary and secondary distribution levels, which although experienced in some part by mobilehome parks, the exact level is unknown. We, in fact, know of no way in which that level can be properly determined without a line loss study.

In the absence of a line loss study, WMA asks that the Commission implement a balancing account for mobilehome park customers. We note, as Edison has, that balancing accounts have been reserved for major proceedings affecting all utility customers. We find unwarranted therefore the imposition of this administrative burden for a single cost related to a specific customer group, the representative of which does not even support methods of calculating the average cost could result in more of the investment costs being recovered in later or earlier years depending on the accounting approach used.

For these reasons, we reject Edison's attempt to shift from the use of the levelized to a nonlevelized fixed charge rate in calculating the DMS-2 discount. If Edison believes that this change is warranted, Edison can use the opportunity of its next general rate case proceeding to provide the required justification of the change and quantification of its impact.

c. Diversity Adjustment

As stated previously, the Commission has recognized the existence of a diversity benefit which arises when a master-metered customer is billed more sales at baseline rates and less sales at nonbaseline rates than are actually consumed by his submetered tenants. (D.86-12-091, at pp. 34-35.) In this proceeding, Edison recommends a diversity adjustment similar to that adopted in PG&E's most recent general rate case to avoid subsidization of master-metered customers by the rest of the residential ratepayers due to an overallocation of kilowatt-hours at lower baseline rates. Edison proposes that a diversity adjustment (1) be made to base rate charges for Schedules DM, DMS-1, and DMS-2, (2) and that these adjustments, be set at $0.13 per unit per day for DM and DMS-1 and at $0.10 per unit per day for DMS-2, and (3) that these adjustments be updated in each subsequent general rate case proceeding.

Edison states that its diversity adjustment for DMS-2 is based on a study of Edison's total population of individually metered mobilehome customers and Edison's proposed baseline allowances and domestic rates. Edison believes that its methodology provides the best available approximation of the usage characteristics of submetered mobilehomes and reflects the diversity for this group as a whole and not the diversity of any one mobilehome park.

the very study needed to identify the existence and extent of the costs in question.

With respect to WMA's assertion that losses represent a small portion of overall bills, we note that our focus is on the discount for which WMA's allowance for distribution energy losses would represent a significant portion. The magnitude of the increase in the discount caused by an allowance for distribution energy losses requires even more that the Commission be assured of the accuracy of the estimate on which that allowance is based.

For the foregoing reasons, the Commission will not adopt WMA's estimate of distribution energy losses nor will we provide for an allowance for those losses in the DMS-2 discount at this time. The only remaining issue is whether Edison should be required, as PG&E was, to conduct a study to analyze the existence and extent of these losses.

Based on the fact that mobilehome park owners do incur distribution energy losses which cannot be properly assessed in the absence of such a study, we find reasonable the undertaking by Edison, in cooperation with WMA, of a study to determine the actual line losses incurred by submetered mobilehome parks. This study, to be completed by Edison's next general rate case, will ensure that the costs associated with those losses are properly reflected in the DMS-2 discount.

b. <u>Fixed Rate Charges</u>

In a departure from its approach in previous years, Edison has proposed in this proceeding to use a nonlevelized, as opposed to a levelized, fixed charge rate in determining the mobilehome park discount. Edison states that this change is based on its interpretation of the applicable code section, California Public Utilities Code Section 739.5. Edison states that Section 739.5 provides that the discount cannot exceed Edison's average cost that it "would have incurred in providing comparable service directly to the users of the service." According to Edison, the

Edison acknowledges that an overstatement of the diversity may have resulted from its not having calculated diversity by park. Edison states, however, that due to the lack of Schedule DMS-2 data at the submetered level for all DMS-2 customers, Edison is unable to determine the actual level of diversity experienced by master-metered customers. Edison states that such a study of individually metered mobilehome customers grouped by park could be undertaken for its test year 1991 general rate case, as PG&E was directed to do in its most recent general rate case.

Edison finds that WMA's methodology for calculating the DMS-2 diversity adjustment using a nonrandom selection of 29 submetered mobilehome parks in Edison's service territory is based on an unrepresentative small sample of DMS-2 customers' data. Edison notes that 29 mobilehome parks represent less than two percent of the total DMS-2 customers in Edison's service territory and that a different set of 29 mobilehome parks could produce quite different results.

In contrast, WMA believes that the diversity benefit which appears simple in principle is much more difficult to assess in application. Until Edison performs a study of usage patterns within mobilehome parks as required for PG&E, WMA states that no diversity adjustment should be made at this time. If the Commission determines that an adjustment is necessary, however, WMA asks that the Commission rely on WMA's data from 29 submetered parks and the baseline allowances adopted in this proceeding. Based on Edison's proposed rates, WMA proposes a diversity adjustment of $1.58 per space per month.

Specifically, WMA states that its study was based on a profile of parks which closely matches the profile of DMS-2 customers and the percentage distributions of both parks and spaces across the climate zones. WMA believes that Edison's failure to study master meters in calculating its adjustment results in the use of a levelized fixed charge rate in calculating the discount for the test year (1988) would result in the discount exceeding Edison's average cost of service. Edison asserts that this average cost can only be produced by using the nonlevelized fixed charge rate.

WMA objects to Edison's use of the nonlevelized fixed charge rate to calculate the DMS-2 discount in this proceeding. According to WMA, the fixed charge rate, which is used to compute the total annual cost of capital investment, has the same value for all of the years during the useful life of the asset when it is levelized. A nonlevelized fixed charge rate, in contrast, changes value for each year of useful life to reflect changes in return, taxes, and book value. WMA states that, based on this distinction between the two rates, the nonlevelized fixed charge rate is higher than the levelized fixed charge rate in the early years and lower in the later years of the useful life.

WMA asserts that because Edison relied on levelized fixed charge rates in the earlier years of the discount, it will have understated the costs in those years should it now be permitted to change to a nonlevelized fixed charge rate. The DMS-2 customer, in WMA's opinion, is therefore deprived of the full cost of the assets by this change in accounting methodology. To make this change, WMA also believes that Edison should have first determined a true need for doing so and then, if the change were warranted, ensure that its figures were adjusted to make up for the earlier deficit.

WMA contends that Edison's use of the nonlevelized fixed charge rate is inappropriate for these additional reasons: (1) Edison's interpretation of Section 739.5, as requiring this change, is "highly technical"; (2) the change will require complex accounting adjustments, a result disputed by Edison; and (3) the change will bring instability to the discount amount. WMA also asserts that, even if a nonlevelized fixed charge rate were used, Edison's calculation is flawed as it fails to identify the true disregard of the fundamental principle that diversity can only occur at the master meter level. WMA asserts that its separate consideration of each master meter identifies no diversity benefit at all. WMA also believes Edison's study is flawed because it (1) relies on kilowatt-hour sales forecasts which are inexplicably well above forecasted levels for DMS-2 customers for an identical period of time, (2) fails to consider distribution system losses, and (3) fails to account for common area usage which occurs in most submetered parks.

WMA states that for PG&E the Commission accepted PG&E's study only because no alternate approach to calculating the diversity adjustment was available. WMA believes that it has presented such a reasonable alternative in this proceeding and that to adopt Edison's studies would be to duplicate the mistakes made by PG&E. Knowing of the flaws in PG&E's study, WMA believes that Edison had the time and opportunity to improve its study, but failed to do so.

The issue of a diversity benefit is a new one for Edison's mobilehome park customers. We recognize, as we did for PG&E in D.86-12-091, however, that the need to make this adjustment exists presently to correct an inequity to other customers resulting from the billing of submetered mobilehome parks. The methodology for calculating this adjustment is obviously not perfected and requires additional data that was not available at the time of this proceeding. We also do not believe, as WMA suggests, that sufficient time was available between the issuance of D.86-12-091 and hearings in this proceeding for Edison to have "corrected" the errors in PG&E's study and performed a study based on usage patterns of individual mobilehome parks.

We are concerned, however, with the discrepancy in estimates of this adjustment between Edison's $.10 per space per day, equaling an approximate $3.00 per space per month adjustment, and WMA's proposed $1.58 per space per month adjustment. Edison average fixed charge rates for all assets in each account. For all of these reasons, WMA urges that, in the absence of a line loss allocation, the DMS-2 discount be fixed at $7.82 per space per month based on the application of the levelized fixed charge rates.

We share WMA's concern with Edison's decision to switch from using a levelized to a nonlevelized fixed charge rate in calculating the DMS-2 discount. We find that Edison's reliance on its interpretation of Section 739.5 alone is not sufficient to warrant a change which could have serious economic repercussions for the affected customer group. The distinction between levelized and nonlevelized fixed charge rates makes inquiry into the impact of using the levelized fixed charge rates for many years and switching now to a fixed charge rate critical to our approval of that change. In order to make the change, we therefore need to know specifically whether the levelized fixed charge rate did in fact represent Edison's average costs in prior years; the extent to which those costs were under-stated or over-stated, if at all, by using a levelized fixed charge rate; and the extent to which it fails to represent Edison's average cost now.

We also find it unlikely that the Legislature intended that, for purposes of determining the mobilehome park discount, the utility's average costs were to be developed in isolation for each test year without regard to the manner in which those costs had been determined in prior years. Certainly, enough flexibility was intended under the statute to recognize the possibility that methods of calculating the average cost could result in more of the investment costs being recovered in later or earlier years depending on the accounting approach used.

For these reasons, we reject Edison's attempt to shift from the use of the levelized to a nonlevelized fixed charge rate in calculating the DMS-2 discount. If Edison believes that this change is warranted, Edison can use the opportunity of its next has even acknowledged the potential of an overstatement of the diversity benefit in its approach. We also note, although PG&E and Edison are different utilities with different rate structures, that PG&E's discount of $1.59 per space per month for electric usage based on its proposed baseline allowances more closely mirrors the proposal of WMA.

In the absence of the appropriate study, we believe that it is reasonable and equitable to adopt a conservative estimate of the diversity adjustment. Such an estimate is represented by WMA's proposed $1.58 per space per month which we will adopt in this proceeding. We also will follow the course established for PG&E and apply this factor to reducing the submetered discount, as opposed to base rate charges as proposed by Edison. We will similarly direct Edison to derive diversity factors for its next general rate case based on the usage patterns of mobilehome parks which it individually meters. We concur with WMA that this study requires the consideration of usage related to each master meter.

d. Adopted DMS-1 and DMS-2 Discounts

Having concluded that distribution energy losses will not be recognized in the DMS-2 discount, but that the levelized fixed charge rate should continue to be used in its calculation, we find reasonable WMA's proposed discount for DMS-2 of $7.82 per space per month or $0.26 per space per day, WMA's estimated discount absent the line loss allowance. Based on our findings regarding the diversity adjustment, the actual DMS-2 discount, however, must be reduced by our adopted diversity factor of $1.58 per space per month to yield our adopted discount for the DMS-2 schedule of $6.34 per space per month.

As we mentioned previously, Edison had also proposed a submetering discount for the DMS-1 schedule and diversity factors for schedules DMS-1 and DM (a master-meter schedule closed to new customers after 1978. Specifically, Edison proposes to maintain the submetering discount for the DMS-1 schedule at its current general rate case proceeding to provide the required justification of the change and quantification of its impact.

c. Diversity Adjustment

As stated previously, the Commission has recognized the existence of a diversity benefit which arises when a master-metered customer is billed more sales at baseline rates and less sales at nonbaseline rates than are actually consumed by his submetered tenants. (D.86-12-091, at pp. 34-35.) In this proceeding, Edison recommends a diversity adjustment similar to that adopted in PG&E's most recent general rate case to avoid subsidization of master-metered customers by the rest of the residential ratepayers due to an overallocation of kilowatt-hours at lower baseline rates. Edison proposes that a diversity adjustment (1) be made to base rate charges for Schedules DM, DMS-1, and DMS-2, (2) and that these adjustments, be set at $0.13 per unit per day for DM and DMS-1 and at $0.10 per unit per day for DMS-2, and (3) that these adjustments be updated in each subsequent general rate case proceeding.

Edison states that its diversity adjustment for DMS-2 is based on a study of Edison's total population of individually metered mobilehome customers and Edison's proposed baseline allowances and domestic rates. Edison believes that its methodology provides the best available approximation of the usage characteristics of submetered mobilehomes and reflects the diversity for this group as a whole and not the diversity of any one mobilehome park.

Edison acknowledges that an overstatement of the diversity may have resulted from its not having calculated diversity by park. Edison states, however, that due to the lack of Schedule DMS-2 data at the submetered level for all DMS-2 customers, Edison is unable to determine the actual level of diversity experienced by master-metered customers. Edison states that such a study of individually metered mobilehome customers grouped by park could be undertaken for its test year 1991 general level of $2.12 per space per month to include a diversity factor for both the DMS-1 and DM schedules of $4.00 per space per month. Edison's diversity factors for these schedules were developed based on a study which used the same methodology which yielded Edison's proposed DMS-2 diversity factor.

Although we did not adopt for PG&E a diversity factor for other than mobilehome parks, it is clear that a diversity benefit exists with respect to all master-metered customers. For this reason, we believe that adjustments for this diversity benefit should also be reflected in Edison's DM and DMS-1 schedules. The diversity factors proposed by Edison for these schedules, however, were developed based on the same methodology as was used in the study conducted for DMS-2 customers, the results of which we have not adopted. The DM and DMS-1 diversity factor proposed by Edison should therefore be reduced proportionately to reflect the difference between Edison's proposed and our adopted DMS-2 diversity factor.

We also note that the DMS-1 discount proposed by Edison does not appear to be based on a current study. Due to this circumstance, we find that the DMS-1 discount should be proportionately increased in keeping with our increase in the DMS-2 discount and should be based on an approach which maintains the current ratio between the DMS-1 and DMS-2 discounts.

We therefore adopt a diversity factor for DM and DMS-1 of $2.43 per space per month or $0.08 per space per day, and a DMS-1 discount of $2.41 per space per month which similarly converts to $0.08 per space per day. The effect of reducing the DMS-1 discount by the amount of the diversity factor is obviously to provide an undiscounted rate to those customers. We further direct Edison to conduct a diversity study for DM and DMS-1 customers for its next general rate case consistent with the study ordered for DMS-2 customers. This study should therefore focus on the usage patterns rate case, as PG&E was directed to do in its most recent general rate case.

Edison finds that WMA's methodology for calculating the DMS-2 diversity adjustment using a nonrandom selection of 29 submetered mobilehome parks in Edison's service territory is based on an unrepresentative small sample of DMS-2 customers' data. Edison notes that 29 mobilehome parks represent less than two percent of the total DMS-2 customers in Edison's service territory and that a different set of 29 mobilehome parks could produce quite different results.

In contrast, WMA believes that the diversity benefit which appears simple in principle is much more difficult to assess in application. Until Edison performs a study of usage patterns within mobilehome parks as required for PG&E, WMA states that no diversity adjustment should be made at this time. If the Commission determines that an adjustment is necessary, however, WMA asks that the Commission rely on WMA's data from 29 submetered parks and the baseline allowances adopted in this proceeding. Based on Edison's proposed rates, WMA proposes a diversity adjustment of $1.58 per space per month.

Specifically, WMA states that its study was based on a profile of parks which closely matches the profile of DMS-2 customers and the percentage distributions of both parks and spaces across the climate zones. WMA believes that Edison's failure to study master meters in calculating its adjustment results in the disregard of the fundamental principle that diversity can only occur at the master meter level. WMA asserts that its separate consideration of each master meter identifies no diversity benefit at all. WMA also believes Edison's study is flawed because it (1) relies on kilowatt-hour sales forecasts which are inexplicably well above forecasted levels for DMS-2 customers for an identical period of time, (2) fails to consider distribution system losses, and (3) of the multifamily dwellings and mobilehome parks individually metered and served under the DM and DMS-1 schedules.

e. Applicability of DMS-2 Schedule to RV Parks

Finally, we address the request of certain RV park owners for the inclusion of recreational vehicle parks in the DMS-2 schedule or, in the alternative, the establishment of a new, similar schedule for RV parks. The RV park owners state that these changes are needed in response to (1) the difficult economic conditions facing RV park owners; (2) the change in customers' choosing smaller, more portable, and less expensive RV units as residences in favor of large mobilehomes; and (3) the need, due to this change from mobilehomes to RVs as residential units, to ensure baseline allowances for RV owners.

The RV park owners believe that the choice of living unit should not deprive any resident of his entitlement to a baseline allowance. Further, the RV park owners assert that the permanence of the RV as a residence has been recognized by state law in which the provisions and rights of the Mobilehome Tenancy Law (Cal.Civ.Code Section 798, et seq.) has been made applicable to recreational vehicle tenants which have established their tenancy in a park for nine months or longer. (Recreational Vehicle Occupancy Law (Cal.Civ.Code Section 799.20 et seq.).)

In keeping with these laws and changed social conditions, the RV park owners proposed in their "closing" brief filed on July 31, 1987, that the Commission adopt one of the following alternatives to ensure the extension of baseline to RV tenants:

1. The definition of "mobilehome park multifamily accommodation" under Edison's tariff Rule 1 should be changed to include residential units as defined by the Recreational Vehicle Occupancy Law and the Mobilehome Tenancy Law (9 month tenancy) and to include RV parks where 50% or more of the spaces or lots submetered are leased for 30 days or longer and are occupied for nine months out of the year.

fails to account for common area usage which occurs in most submetered parks.

WMA states that for PG&E the Commission accepted PG&E's study only because no alternate approach to calculating the diversity adjustment was available. WMA believes that it has presented such a reasonable alternative in this proceeding and that to adopt Edison's studies would be to duplicate the mistakes made by PG&E. Knowing of the flaws in PG&E's study, WMA believes that Edison had the time and opportunity to improve its study, but failed to do so.

The issue of a diversity benefit is a new one for Edison's mobilehome park customers. We recognize, as we did for PG&E in D.86-12-091, however, that the need to make this adjustment exists presently to correct an inequity to other customers resulting from the billing of submetered mobilehome parks. The methodology for calculating this adjustment is obviously not perfected and requires additional data that was not available at the time of this proceeding. We also do not believe, as WMA suggests, that sufficient time was available between the issuance of D.86-12-091 and hearings in this proceeding for Edison to have "corrected" the errors in PG&E's study and performed a study based on usage patterns of individual mobilehome parks.

We are concerned, however, with the discrepancy in estimates of this adjustment between Edison's $.10 per space per day, equaling an approximate $3.00 per space per month adjustment, and WMA's proposed $1.58 per space per month adjustment. Edison has even acknowledged the potential of an overstatement of the diversity benefit in its approach. We also note, although PG&E and Edison are different utilities with different rate structures, that PG&E's discount of $1.59 per space per month for electric usage based on its proposed baseline allowances more closely mirrors the proposal of WMA.

2. The DMS-2 schedule should be amended to alter the present "applicability" paragraph and to add a special condition so as to include and extend the discount to recreational vehicle parks which meet the criteria outlined in the above alternative. The RV park owners propose that the discount for RV parks with vacancy factors and transient load would be established as a percentage of the total spaces submetered upon proof of average number of spaces occupied on a month to month basis over the past 12-month period in the park or upon actual spaces occupied on a month to month basis where the park has not established a record from which to compute the average.

3. In the absence of either of these two alternatives, a new Schedule DMS-3 should be established which would be identical to DMS-2 except for the following: (1) all references to "mobilehome" would be replaced by "recreational vehicle," and (2) the "applicability" and special conditions of the tariff would match those discussed above related to the modification of DMS-2.

The RV park owners assert that Edison objections to their proposals merely reflect Edison's unwillingness to change past practices despite a change in residential dwelling habits. Specifically, the RV park owners charge that Edison has (1) misinterpreted the application of DMS-2; (2) denied baseline benefits to individuals who have chosen to reside in a smaller, more portable dwelling unit; and (3) failed to recognize the similarities in the intentions and legal status of RV and mobilehome park owners.

Edison opposes the inclusion of RV parks under either Schedule DMS-2 or a new, similarly designed rate schedule. Edison states that it already has a rate schedule (DMS-1) which provides a baseline allowance and a discount for submetered service and which is applicable to an RV park meter that meets certain criteria.

In the absence of the appropriate study, we believe that it is reasonable and equitable to adopt a conservative estimate of the diversity adjustment. Such an estimate is represented by WMA's proposed $1.58 per space per month which we will adopt in this proceeding. We also will follow the course established for PG&E and apply this factor to reducing the submetered discount, as opposed to base rate charges as proposed by Edison. We will similarly direct Edison to derive diversity factors for its next general rate case based on the usage patterns of mobilehome parks which it individually meters. We concur with WMA that this study requires the consideration of usage related to each master meter.

d. <u>Adopted DMS-1 and DMS-2 Discounts</u>

Having concluded that distribution energy losses will not be recognized in the DMS-2 discount, but that the levelized fixed charge rate should continue to be used in its calculation, we find reasonable WMA's proposed discount for DMS-2 of $7.82 per space per month or $0.26 per space per day, WMA's estimated discount absent the line loss allowance. Based on our findings regarding the diversity adjustment, the actual DMS-2 discount, however, must be reduced by our adopted diversity factor of $1.58 per space per month to yield our adopted discount for the DMS-2 schedule of $6.34 per space per month.

As we mentioned previously, Edison had also proposed a submetering discount for the DMS-1 schedule and diversity factors for schedules DMS-1 and DM (a master-meter schedule closed to new customers after 1978. Specifically, Edison proposes to maintain the submetering discount for the DMS-1 schedule at its current level of $2.12 per space per month to include a diversity factor for both the DMS-1 and DM schedules of $4.00 per space per month. Edison's diversity factors for these schedules were developed based on a study which used the same methodology which yielded Edison's proposed DMS-2 diversity factor.

This criteria includes the installation of the park prior to December 7, 1981, and the presence in that park of exclusively nontransient, single-family accommodations used as permanent residences on a single Edison meter. Edison states that RV parks with a mixture of transient and nontransient load do not qualify for DMS-1 service and that the Commission has ruled that after December 7, 1981, single-family dwellings, in other than a mobilehome park, must have an individual meter. (D.88651, at p. 23; D.88969, at p. 57.)

Edison additionally states that the DMS-2 rate schedule is expressly limited to mobilehome parks and was designed only for such parks. According to Edison, this schedule does not take into account the RV park, but rather is based specifically on the costs to serve mobilehome parks and the reliability of the construction and maintenance of their electrical distribution systems. Edison further notes that separate California laws apply to and define "mobilehome parks" and "RV parks." Edison also states that the Commission did not intend that RV parks with transient accommodations or transient tenants receive residential baseline rates. (D.86087 at p. 9.)

Edison also argues against the Commission's consideration of the RV park owners' proposed new rate Schedule DMS-3. Edison states that this proposal was presented for the first time in this proceeding in the RV park owners' "closing brief" and that Edison has therefore not had the opportunity to analyze or respond to this proposal.

Although Edison urges the rejection of this proposal on this ground alone, Edison also asserts that the proposal is not supported by the record or by reason. Specifically, Edison believes that the same reasons which demonstrate that the DMS-2 schedule is inapplicable to RV parks also support the rejection of the proposed DMS-3 schedule. Additionally, Edison states that the new rate schedule would impose substantial administrative costs on

Although we did not adopt for PG&E a diversity factor for other than mobilehome parks, it is clear that a diversity benefit exists with respect to all master-metered customers. For this reason, we believe that adjustments for this diversity benefit should also be reflected in Edison's DM and DMS-1 schedules. The diversity factors proposed by Edison for these schedules, however, were developed based on the same methodology as was used in the study conducted for DMS-2 customers, the results of which we have not adopted. The DM and DMS-1 diversity factor proposed by Edison should therefore be reduced proportionately to reflect the difference between Edison's proposed and our adopted DMS-2 diversity factor.

We also note that the DMS-1 discount proposed by Edison does not appear to be based on a current study. Due to this circumstance, we find that the DMS-1 discount should be proportionately increased in keeping with our increase in the DMS-2 discount and should be based on an approach which maintains the current ratio between the DMS-1 and DMS-2 discounts.

We therefore adopt a diversity factor for DM and DMS-1 of $2.43 per space per month or $0.08 per space per day, and a DMS-1 discount of $2.41 per space per month which similarly converts to $0.08 per space per day. The effect of reducing the DMS-1 discount by the amount of the diversity factor is obviously to provide an undiscounted rate to those customers. We further direct Edison to conduct a diversity study for DM and DMS-1 customers for its next general rate case consistent with the study ordered for DMS-2 customers. This study should therefore focus on the usage patterns of the multifamily dwellings and mobilehome parks who are individually metered and data should be grouped at the master meter level (apartment building or mobilehome park).

e. <u>Applicability of DMS-2 Schedule to RV Parks</u>

Finally, we address the request of certain RV park owners for the inclusion of recreational vehicle parks in the DMS-2

Edison's other ratepayers related to the application and monitoring of the new rate schedule. Edison further asserts that the load and residency requirements proposed by the RV park owners are wholly inadequate to ensure the presence of nontransient, residential tenants.

WMA also opposes the inclusion of recreational vehicle parks in the DMS-2 schedule for the same reasons as those asserted by Edison. In the absence of adequate cost information and the determination of the applicability of residential rates to users of residential vehicle park spaces, WMA states that it is inappropriate to include RV parks within the DMS-2 schedule.

Like Edison, we also have significant problems with the RV park owners' specific proposals. To begin with, a review of the record reflects that none of the RV park owners' alternative rate design proposals set forth in their brief were similarly presented in their testimony. A review of the RV park owners' testimony reveals that this testimony focused on the nature of RV park tenants, the Edison billing histories of certain RV parks, and the perceived need for the application of the DMS-2 schedule to RV parks.

For the RV park owners to present specific rate design proposals in this proceeding after the close of hearings is inequitable and a denial of the opportunity of other parties to cross-examine the RV park owners and to respond to the owners' proposals. This approach also denies the Commission the opportunity to examine these proposals in greater detail to determine their impact on all residential customers and to ensure their reasonableness. For these reasons alone, we find that we are foreclosed from considering the RV park owners' proposed changes and additions to Edison's existing tariffs.

We are not foreclosed, however, from considering the need for such tariff changes in the future. In this regard, we believe that the RV park owners have actually raised two separate issues:

schedule or, in the alternative, the establishment of a new, similar schedule for RV parks. The RV park owners state that these changes are needed in response to (1) the difficult economic conditions facing RV park owners; (2) the change in customers' choosing smaller, more portable, and less expensive RV units as residences in favor of large mobilehomes; and (3) the need, due to this change from mobilehomes to RVs as residential units, to ensure baseline allowances for RV owners.

The RV park owners believe that the choice of living unit should not deprive any resident of his entitlement to a baseline allowance. Further, the RV park owners assert that the permanence of the RV as a residence has been recognized by state law in which the provisions and rights of the Mobilehome Tenancy Law (Cal.Civ.Code Section 798, et seq.) have been made applicable to recreational vehicle tenants which have established a tenancy in a park for nine months or longer. (Recreational Vehicle Occupancy Law (Cal.Civ.Code Section 799.20 et seq.).)

In keeping with these laws and changed social conditions, the RV park owners proposed in their "closing" brief filed on July 31, 1987, that the Commission adopt one of the following alternatives to ensure the extension of baseline to RV tenants:

1. The definition of "mobilehome park multifamily accommodation" under Edison's tariff Rule 1 should be changed to include residential units as defined by the Recreational Vehicle Occupancy Law and the Mobilehome Tenancy Law (9 month tenancy) and to include RV parks where 50% or more of the spaces or lots submetered are leased for 30 days or longer and are occupied for nine months out of the year.

2. The DMS-2 schedule should be amended to alter the present "applicability" paragraph and to add a special condition so as to include and extend the discount to recreational vehicle parks which meet the criteria outlined in the above alternative. The RV park owners propose that the

(1) the need to apply baseline allowances to recreational vehicle tenants and (2) the need to extend a master-metered discount to RV park owners similar to that in place for mobilehome park owners.

With respect to baseline allowances, to the extent that the alleged trend toward recreational vehicles as permanent residences can be demonstrated, the Commission would be remiss in not ensuring that each of these "residents" received the appropriate baseline allowance. To do so, however, the Commission would need proof of the existence of such residential use and a reasonable basis for distinguishing between transient and nontransient RV tenants. Without objective criteria on which to judge entitlement to a baseline allowance, the Commission could not be assured that such allowances were being properly limited to residential customers only. The Commission must also consider the resulting administrative burden imposed on Edison and ensure that Edison can properly monitor its system and billing.

The burden of proving the existence of the change from mobilehome to recreational vehicle as a permanent residence has not, however, been met in this proceeding. Additionally, the record is not sufficient to determine the exact residence requirements, the need for monitoring, or the appropriate charges for master-metered and submetered service to recreational vehicles.

The application of the DMS-2 schedule to RV parks requires the further determination of the propriety of a master-metered discount being provided to RV park owners. As Edison has correctly pointed out, the development of the DMS-2 schedule was the process of both a legislative and an administrative (Commission) effort which focused on the exact costs and needs of the master-metered mobilehome park. Before any similar tariff could be adopted for the RV park, a level of analysis beyond that undertaken in this proceeding would certainly be required. That analysis would, of course, need to include consideration of the costs associated with installing, operating, and owning the discount for RV parks with vacancy factors and transient load would be established as a percentage of the total spaces submetered upon proof of average number of spaces occupied on a month to month basis over the past 12-month period in the park or upon actual spaces occupied on a month to month basis where the park has not established a record from which to compute the average.

3. In the absence of either of these two alternatives, a new Schedule DMS-3 should be established which would be identical to DMS-2 except for the following: (1) all references to "mobilehome" would be replaced by "recreational vehicle," and (2) the "applicability" and special conditions of the tariff would match those discussed above related to the modification of DMS-2.

The RV park owners assert that Edison objections to their proposals merely reflect Edison's unwillingness to change past practices despite a change in residential dwelling habits. Specifically, the RV park owners charge that Edison has (1) misinterpreted the application of DMS-2; (2) denied baseline benefits to individuals who have chosen to reside in a smaller, more portable dwelling unit; and (3) failed to recognize the similarities in the intentions and legal status of RV and mobilehome park owners.

Edison opposes the inclusion of RV parks under either Schedule DMS-2 or a new, similarly designed rate schedule. Edison states that it already has a rate schedule (DMS-1) which provides a baseline allowance and a discount for submetered service and which is applicable to an RV park meter that meets certain criteria. This criteria includes the installation of the park prior to December 7, 1981, and the presence in that park of exclusively nontransient, single-family accommodations used as permanent residences on a single Edison meter. Edison states that RV parks with a mixture of transient and nontransient load do not qualify submetering distribution facilities within the RV park and the propriety of applying the same statutory standards for establishing the discounts for RV parks and mobilehome parks.

As our foregoing discussion makes clear, we are not in a position in this proceeding to adopt any of the rate design changes proposed by the RV park owners. We do find, however, that sufficient reasons have been suggested by the RV park owners for this Commission to consider the need for tariff changes extending baseline allowances or master-metered discounts to RV tenants and RV park owners. We will therefore direct Edison to conduct a study of the need for and feasibility of such tariff changes and present the results of that study in its next general rate case. Edison's study should include the examination of tariff language aimed at ensuring that RV "residents" receive baseline allowances to which they are entitled. To undertake this task, Edison will be required to provide standards by which it can objectively judge and realistically monitor the status of the RV tenant.

C. Lighting - Small and Medium Power Customer Group

Testimony in this proceeding on the rate design to be adopted for the small and medium power customer group centered on the recommendations of Edison, PSD, and SCRUB. Edison and PSD in their joint exhibit on rate design (Exhibit 87) reached agreement on most of the components of these rate schedules. SCRUB and Edison, however, failed to agree on the issues of conjunctive billing and the waiver of non-time related demand charges for schools.

The agreement reached by Edison and PSD includes the following:

1. Schedule Changes. PSD has agreed to Edison's proposal to eliminate Schedule GS-1, creating two new schedules in its place. The first would be GS-SP, for single-phase customers. The second would be GS-TP for three-phase customers, but its use would be limited to existing GS-1 three-phase customers, with new three-phase

for DMS-1 service and that the Commission has ruled that after December 7, 1981, single-family dwellings, in other than a mobilehome park, must have an individual meter. (D.88651, at p. 23; D.88969, at p. 57.)

Edison additionally states that the DMS-2 rate schedule is expressly limited to mobilehome parks and was designed only for such parks. According to Edison, this schedule does not take into account the RV park, but rather is based specifically on the costs to serve mobilehome parks and the reliability of the construction and maintenance of their electrical distribution systems. Edison further notes that separate California laws apply to and define "mobilehome parks" and "RV parks." Edison also states that the Commission did not intend that RV parks with transient accommodations or transient tenants receive residential baseline rates. (D.86087 at p. 9.)

Edison also argues against the Commission's consideration of the RV park owners' proposed new rate Schedule DMS-3. Edison states that this proposal was presented for the first time in this proceeding in the RV park owners' "closing brief" and that Edison has therefore not had the opportunity to analyze or respond to this proposal.

Although Edison urges the rejection of this proposal on this ground alone, Edison also asserts that the proposal is not supported by the record or by reason. Specifically, Edison believes that the same reasons which demonstrate that the DMS-2 schedule is inapplicable to RV parks also support the rejection of the proposed DMS-3 schedule. Additionally, Edison states that the new rate schedule would impose substantial administrative costs on Edison's other ratepayers related to the application and monitoring of the new rate schedule. Edison further asserts that the load and residency requirements proposed by the RV park owners are wholly inadequate to ensure the presence of nontransient, residential tenants.

customers moving to the demand-metered Schedules GS-2, TOU-GS, and PA-2 or PA-1, a connected load schedule based on their operation. In addition, Edison has accepted the PSD recommendation that Schedule GS-TP be eliminated effective December 31, 1990, thus placing all three-phase customers on one of the above schedules.

2. <u>Customer Charges</u>. Edison and PSD agree that the customer charge for Schedules GS-2 and TOU-GS should be set at $30.00 per month. In addition, Schedule TOU-GS should include a $7.00 per month meter charge.

3. <u>Demand Charges</u>. Edison and PSD agree that for Schedule GS-2, the summer time-related demand charge should be set at $5.70 per kW with no demand charge in the winter. Edison and PSD also agree that the non-time-related demand charge should be set at $2.60 per kW of current billing period demand or 50 percent of the highest demand over the previous 11 months, whichever is greater.

4. <u>Energy Charges</u>. Edison and PSD agree that energy charges for proposed Schedules GS-SP and GS-TP should not be seasonally differentiated and should be set residually to collect any revenue requirement not collected through the customer charge. Edison and PSD agree that Schedule GS-2 should not include seasonal differentiation of the energy charges and should have a blocked energy rate set at 5.0 cents/kWh for all kWh in excess of 300 kWh/kW. The energy rate for the first block is proposed to be determined residually to collect the remainder of the revenue requirement not collected through the customer charge, demand charges, and second block energy rate.

These agreements of PSD and Edison were not opposed by any other party. We find, for the most part, that each is reasonable having been based on sound rate design principles. The

WMA also opposes the inclusion of recreational vehicle parks in the DMS-2 schedule for the same reasons as those asserted by Edison. In the absence of adequate cost information and the determination of the applicability of residential rates to users of residential vehicle park spaces, WMA states that it is inappropriate to include RV parks within the DMS-2 schedule.

Like Edison, we also have significant problems with the RV park owners' specific proposals. To begin with, a review of the record reflects that none of the RV park owners' alternative rate design proposals set forth in their brief were similarly presented in their testimony. A review of the RV park owners' testimony reveals that this testimony focused on the nature of RV park tenants, the Edison billing histories of certain RV parks, and the perceived need for the application of the DMS-2 schedule to RV parks.

For the RV park owners to present specific rate design proposals in this proceeding after the close of hearings is inequitable and a denial of the opportunity of other parties to cross-examine the RV park owners and to respond to the owners' proposals. This approach also denies the Commission the opportunity to examine these proposals in greater detail to determine their impact on all residential customers and to ensure their reasonableness. For these reasons alone, we find that we are foreclosed from considering the RV park owners' proposed changes and additions to Edison's existing tariffs.

We are not foreclosed, however, from considering the need for such tariff changes in the future. In this regard, we believe that the RV park owners have actually raised two separate issues: (1) the need to apply baseline allowances to recreational vehicle tenants and (2) the need to extend a master-metered discount to RV park owners similar to that in place for mobilehome park owners.

With respect to baseline allowances, to the extent that the alleged trend toward recreational vehicles as permanent only exception is Edison's and PSD's recommendation to "ratchet" the demand charge. "Ratcheting" refers to the setting of the demand charge at a percentage of the highest demand over a fixed period of time. In this proceeding, Edison has proposed ratchets for all demand-metered schedules. Because this issue was discussed in greater depth for the large power customer group, we reserve our discussion of that issue to that portion of this order. We have found, based on that discussion, however, that ratcheting of demand charges is inappropriate. Consistent with that finding, we similarly do not adopt Edison's and PSD's ratchet proposal for demand charges under the small and medium power rate schedules.

1. Non-TOU Schedules

For the non-TOU schedules for small and medium power customers, the remaining issues between Edison and PSD involve the calculation of customer charges and energy rates. With respect to customer charges, the parties agree that these charges should be set on a daily basis. Edison, however, proposes that the charges be set at 25 cents per day, while PSD recommends a rate of 15 cents per day. PSD states that its daily rate is derived from a $4.50 per month customer charge based on marginal customer costs.

Edison states that its approach to calculating the non-demand customer charge is more appropriate than PSD's method because it is designed to recover a greater percentage of fixed costs in the fixed customer charge without producing adverse bill impacts. We concur with Edison and will adopt its proposed daily customer charge of 25 cents per day for Schedules GS-SP, GS-TP, and TC-1.

Edison states that it has proposed the same methodology for setting the Schedule TC-1 energy rate as proposed for Schedules GS-SP and GS-TP. PSD has, in contrast, set the Schedule TC-1 average rate the same as the proposed Schedule GS-SP/TP average rate based on similarities in the size of customers served on Schedules GS-SP, GS-TP, and TC-1. Edison asserts that although residences can be demonstrated, it may be appropriate for RV tenants to receive baseline allowances. To do so, however, the Commission would need proof of the existence of such residential use and a reasonable basis for distinguishing between transient and nontransient RV tenants. Without objective criteria to develop a baseline allowance, the Commission could not be assured that such allowances were being properly limited to residential customers only. The Commission must also consider the resulting administrative burden imposed on Edison and ensure that Edison can properly monitor its system and billing.

The burden of proving the existence of the change from mobilehome to recreational vehicle as a permanent residence has not, however, been met in this proceeding. Additionally, the record is not sufficient to determine the exact residence requirements, the need for monitoring, or the appropriate charges for master-metered and submetered service to recreational vehicles.

The application of the DMS-2 schedule to RV parks requires the further determination of the propriety of a master-metered discount being provided to RV park owners. As Edison has correctly pointed out, the development of the DMS-2 schedule was the process of both a legislative and an administrative (Commission) effort which focused on the exact costs and needs of the master-metered mobilehome park. Before any similar tariff could be adopted for the RV park, a level of analysis beyond that undertaken in this proceeding would certainly be required. That analysis would, of course, need to include consideration of the costs associated with installing, operating, and owning the submetering distribution facilities within the RV park and the propriety of applying the same statutory standards for establishing the discounts for RV parks and mobilehome parks.

As our foregoing discussion makes clear, we are not in a position in this proceeding to adopt any of the rate design changes proposed by the RV park owners. We do find, however, that

TC-1 customers are similar in size to GS-SP and GS-TP customers, their usage characteristics are dissimilar since traffic lights operate 24 hours per day. In Edison's opinion, their rate should therefore not be arbitrarily set at the average of GS-SP and GS-TP whose load characteristics are primarily on-peak.

To the extent possible, it is our intent in rate design to provide proper price signals based on marginal costs and the customer's usage characteristics. We believe that Edison's proposed Schedule TC-1 energy rate accomplishes this goal and should be adopted.

2. Time-Of-Use Schedules (TOU-GS and TOU-GS-SOP)

Both Edison and PSD propose that Edison's Schedule TOU-GS, applicable to small and medium power customers with maximum demands below 500 kW, should be kept open and that a new schedule, TOU-GS-SOP, should be made available to the same group of customers. The structure of Edison's proposed rate Schedule TOU-GS-SOP is the same as the TOU-8-SOP rate schedule and includes a fourth time period called the "super off-peak" period for the hours between midnight and 6:00 a.m. Edison believes that this proposed rate schedule can promote cost effective usage during the super-off-peak period and thus help mitigate its minimum load problem. The availability of the option, in Edison's opinion, will also help shift loads such as air conditioning from on-peak to off-peak by giving cost-effective incentives and promoting thermal storage systems.

With respect to the charges under these rate schedules, Edison and PSD have agreed on the customer charges, the demand charges, and the amount of revenue to be collected from the TOU-GS and TOU-GS-SOP rate schedules. The revenue allocation for these rate schedules should be based on an equal percent of present rate revenues consistent with our previous adoption of Edison's proposed intra-class revenue allocation.

sufficient reasons have been suggested by the RV park owners for this Commission to consider the need for tariff changes extending baseline allowances or master-metered discounts to RV tenants and RV park owners. We will therefore direct Edison to conduct a study of the need for and feasibility of such tariff changes and present the results of that study in its next general rate case. To undertake this task, Edison will be required to provide standards by which it can objectively judge and realistically monitor the status of the RV tenant.

C. Lighting - Small and Medium Power Customer Group

Testimony in this proceeding on the rate design to be adopted for the small and medium power customer group centered on the recommendations of Edison, PSD, and SCRUB. Edison and PSD in their joint exhibit on rate design (Exhibit 87) reached agreement on most of the components of these rate schedules. SCRUB and Edison, however, failed to agree on the issues of conjunctive billing and the waiver of non-time related demand charges for schools.

The agreement reached by Edison and PSD includes the following:

1. Schedule Changes. PSD has agreed to Edison's proposal to eliminate Schedule GS-1, creating two new schedules in its place. The first would be GS-SP, for single-phase customers. The second would be GS-TP for three-phase customers, but its use would be limited to existing GS-1 three-phase customers, with new three-phase customers moving to the demand-metered Schedules GS-2, TOU-GS, and PA-2 or PA-1, a connected load schedule based on their operation. In addition, Edison has accepted the PSD recommendation that Schedule GS-TP be eliminated effective December 31, 1990, thus placing all three-phase customers on one of the above schedules.

2. Customer Charges. Edison and PSD agree that the customer charge for Schedules GS-2

Since the conclusion of the hearings, PSD and Edison reached further agreement on certain modification to the TOU-GS schedules. These modifications are as follows:

1. The customer charge is reduced from \$250/month to \$30/month;

2. The non-time-related demand charge is reduced from \$2.70/kW to \$2.60/kW. The above changes are made so that the customer and non-time-related demand charges conform with the equivalent charges on the GS-2 rate schedule;

3. The time-related demand charges are reduced to conform with the corresponding charges reflected in the joint exhibit (Exhibit 87); and

4. The revenue shortfall resulting from the above adjustments is allocated to the summer on- and mid-peak and winter mid-peak energy charges on the bases agreed to by the parties.

For the TOU-GS and TOU-GS-SOP rate schedules, the only difference between Edison and PSD was the calculation of the energy charge. Instead of using the EPMC approach advocated by PSD, Edison set the off-peak and super off-peak energy charges at predetermined levels of 5.0 cents/kWh and 3.7 cents/kWh with the other time-differentiated energy charges being set on an EPMC basis. Edison states that this approach is consistent with the TOU-8 and TOU-8-SOP rate schedules and ensures a stable rate level for the off-peak and super off-peak energy charges.

We find that the agreements reached by Edison and PSD result in rate structures for the TOU-GS and TOU-GS-SOP schedules which are consistent with our current rate design policies and principles. The two schedules not only offer significant options to customers served under these schedules in terms of controlling energy consumption and costs, but also ensure recovery of the revenue allocated to the class. We therefore find reasonable and

and TOU-GS should be set at $30.00 per month. In addition, Schedule TOU-GS should include a $7.00 per month meter charge.

3. Demand Charges. Edison and PSD agree that for Schedule GS-2, the summer time-related demand charge should be set at $5.70 per kW with no demand charge in the winter. Edison and PSD also agree that the non-time-related demand charge should be set at $2.60 per kW of current billing period demand or 50 percent of the highest demand over the previous 11 months, whichever is greater.

4. Energy Charges. Edison and PSD agree that energy charges for proposed Schedules GS-SP and GS-TP should not be seasonally differentiated and should be set residually to collect any revenue requirement not collected through the customer charge. Edison and PSD agree that Schedule GS-2 should not include seasonal differentiation of the energy charges and should have a blocked energy rate set at 5.0 cents/kWh for all kWh in excess of 300 kWh/kW. The energy rate for the first block is proposed to be determined residually to collect the remainder of the revenue requirement not collected through the customer charge, demand charges and second block energy rate.

These agreements of PSD and Edison were not opposed by any other party. We find, for the most part, that each is reasonable having been based on sound rate design principles. The only exception is Edison's and PSD's recommendation to "ratchet" the demand charge. "Ratcheting" refers to the setting of the demand charge at a percentage of the highest demand over a fixed period of time. In this proceeding, Edison has proposed ratchets for all demand-metered schedules. Because this issue was discussed in greater depth for the large power customer group, we reserve our discussion of that issue to that portion of this order. We have found, based on that discussion, however, that ratcheting of demand adopt the rate structure for TOU-GS and TOU-GS-SOP to which Edison and PSD have agreed and direct the implementation of these schedules in the manner proposed by these parties. To ensure consistency with our other findings, however, no "ratcheting" of demand charges should be included in these schedules.

With respect to the sole issue in dispute, we find reasonable and adopt the energy charges for the two schedules as proposed by Edison. Edison has adequately demonstrated that these charges are required to ensure consistency and stability in rate levels and between rate schedules.

3. Issues Impacting School Districts

In this proceeding, SCRUB has requested consolidated or "conjunctive" billing at a single rate of all meters at a single school site and all meters within an entire school district. SCRUB also asks that the non-time related demand charge for distribution be waived for school districts if that district enters a formal agreement with Edison to limit energy usage during peak periods to a predetermined level. Edison opposes both of these recommendations.

a. Conjunctive Billing

Conjunctive billing for schools was addressed in PG&E's most recent general rate case. In D.86-12-091 in that proceeding, we found that it was reasonable for PG&E to provide schools taking service from more than one meter at the same site with the opportunity to have their total usage consolidated for billing purposes. (D.86-12-091, at pp. 81-82.) This same finding, however, was not extended to consolidated billing for multiple sites based on our conclusion that no distinction should be made between two or more customers taking service at individual sites and one customer taking service at multiple sites.

We therefore required PG&E to offer conjunctive billing for multiple meters at a single school, and in its next rate case, address the propriety of expanding conjunctive billing to all charges is inappropriate. Consistent with that finding, we similarly do not adopt Edison's and PSD's ratchet proposal for demand charges under the small and medium power rate schedules.

1. Non-TOU Schedules

For the non-TOU schedules for small and medium power customers, the remaining issues between Edison and PSD involve the calculation of customer charges and energy rates. With respect to customer charges, the parties agree that these charges should be set on a daily basis. Edison, however, proposes that the charges be set at 25 cents per day, while PSD recommends a rate of 15 cents per day. PSD states that its daily rate is derived from a $4.50 per month customer charge based on marginal customer costs.

Edison states that its approach to calculating the non-demand customer charge is more appropriate than PSD's method because it is designed to recover a greater percentage of fixed costs in the fixed customer charge without producing adverse bill impacts. We concur with Edison and will adopt its proposed daily customer charge of 25 cents per day for Schedules GS-SP, GS-TP, and TC-1.

Edison states that it has proposed the same methodology for setting the Schedule TC-1 energy rate as proposed for Schedules GS-SP and GS-TP. PSD has, in contrast, set the Schedule TC-1 average rate the same as the proposed Schedule GS-SP/TP average rate based on similarities in the size of customers served on Schedules GS-SP, GS-TP, and TC-1. Edison asserts that although TC-1 customers are similar in size to GS-SP and GS-TP customers, their usage characteristics are dissimilar since traffic lights operate 24 hours per day. In Edison's opinion, their rate should therefore not be arbitrarily set at the average of GS-SP and GS-TP whose load characteristics are primarily on-peak.

To the extent possible, it is our intent in rate design to provide proper price signals based on marginal costs and the customer's usage characteristics. We believe that Edison's customers. (D.86-12-091, at p. 82.) Under the terms of that billing, the school was not to be required to pay for any special facilities needed to achieve consolidation of its bills, but it would be required to pay for the administrative and facilities costs associated with providing service on one site at different locations. (Id., at pp. 81-82.)

In response to D.86-12-091, PG&E filed an advice letter earlier this year seeking Commission approval of two new forms related to conjunctive billing for schools. Of these two billing forms, one reflected on the cost of allocated facilities necessary to provide service at multiple sites, while the other, a simpler form, involved combining meter readings from all accounts at a site and billing them under one rate. These forms were the result of an agreement between PG&E and SCRUB who had also agreed that the forms should be offered on a limited, experimental basis. Specifically, the parties agreed that, due to the costs and complexities of the facility cost agreement, this form would be offered on a test basis to a limited number of schools. The second, simpler option would be offered as a further experiment limited to primary and secondary schools.

By Resolution E-3045, dated August 26, 1987, PG&E was authorized to file these two new forms. The resolution also directed PG&E in its next general rate case to evaluate this conjunctive billing experiment on the basis, among other things, of its revenue effect, the need for its continuation, and the propriety of making the option available to other types of customers.

In this proceeding, as stated previously, SCRUB asks that Edison be required, as PG&E was, to undertake conjunctive billing for schools. SCRUB's request, however, includes not only conjunctive billing for all meters at a single school site, but also all meters at multiple sites within a single school district.

proposed Schedule TC-1 energy rate accomplishes this goal and should be adopted.

2. Time-Of-Use Schedules (TOU-GS and TOU-GS-SOP)

Both Edison and PSD propose that Edison's Schedule TOU-GS, applicable to small and medium power customers with maximum demands below 500 kW, should be kept open and that a new schedule, TOU-GS-SOP, should be made available to the same group of customers. The structure of Edison's proposed rate Schedule TOU-GS-SOP is the same as the TOU-8-SOP rate schedule and includes a fourth time period called the "super off-peak" period for the hours between midnight and 6:00 a.m. Edison believes that this proposed rate schedule can promote cost effective usage during the super-off-peak period and thus help mitigate its minimum load problem. The availability of the option, in Edison's opinion, will also help shift loads such as air conditioning from on-peak to off-peak by giving cost-effective incentives and promoting thermal storage systems.

With respect to the charges under these rate schedules, Edison and PSD have agreed on the customer charges, the demand charges, and the methodology for determining the amount of revenue to be collected from the TOU-GS and TOU-GS-SOP rate schedules. The revenue allocation for these rate schedules should be based on an equal percent of present rate revenues consistent with our previous adoption of Edison's proposed intra-class revenue allocation. The only exception to this finding is for TOU-GS and GS-2 the revenue allocation for which, as previously discussed, is determined by applying the adopted rates to the billing determinants proposed for those schedules by Edison and PSD.

Since the conclusion of the hearings, PSD and Edison reached further agreement on certain modification to the TOU-GS schedules. These modifications are as follows:

1. The customer charge is reduced from $250/month to $30/month;

With respect to this latter request, SCRUB believes that conjunctive billing for multiple sites is required to permit the school district to practice load management and to accurately determine the economics of self-generation. SCRUB states that this type of billing could be undertaken by Edison on an experimental basis subject to certain conditions. These conditions would include (1) Edison's installation of the necessary equipment and implementation of the necessary billing procedures, (2) computation of the bill under the rate schedule that is applicable to the combined usage, and (3) recovery by Edison of the cost of any additional facilities and efforts related to conjunctive billing directly from the districts receiving the service in the form of predetermined, standard monthly service charges.

Edison states that it objects to conjunctive billing for schools for both single sites and multiple sites. Edison believes that conjunctive billing is not cost-effective, "bundles" rather than "unbundles" generation, transmission, and distribution costs; and is not a proper means of reflecting non-time related demand on its distribution system.

With respect to this latter point, Edison believes that inequities in rate design will result if the "benefit" of conjunctive billing is extended to one customer group. Specifically, Edison asserts that diversity among accounts is already recognized by virtue of the design billing parameters which are based on historical "noncoincident" demands. Edison states that as these billing parameters decrease under conjunctive billing, the demand charge must increase proportionately to recover Edison's cost of service. Edison therefore concludes that if only schools are permitted conjunctive billing, all other customers, other than schools, would be adversely affected. Edison notes, however, that conversely if all multiple-site customers were entitled to conjunctive billing, the concept would produce little

2. The non-time-related demand charge is reduced from $2.70/kW to $2.60/kW. The above changes are made so that the customer and non-time-related demand charges conform with the equivalent charges on the GS-2 rate schedule;

3. The time-related demand charges are reduced to conform with the corresponding charges reflected in the joint exhibit (Exhibit 87); and

4. The revenue shortfall resulting from the above adjustments is allocated to the summer on- and mid-peak and winter mid-peak energy charges on the bases agreed to by the parties.

For the TOU-GS and TOU-GS-SOP rate schedules, the only difference between Edison and PSD was the calculation of the energy charge. Instead of using the EPMC approach advocated by PSD, Edison set the off-peak and super off-peak energy charges at predetermined levels of 5.0 cents/kWh and 3.7 cents/kWh with the other time-differentiated energy charges being set on an EPMC basis. Edison states that this approach is consistent with the TOU-8 and TOU-8-SOP rate schedules and ensures a stable rate level for the off-peak and super off-peak energy charges.

We find that the agreements reached by Edison and PSD result in rate structures for the TOU-GS and TOU-GS-SOP schedules which are consistent with our current rate design policies and principles. The two schedules not only offer significant options to customers served under these schedules in terms of controlling energy consumption and costs, but also ensure recovery of the revenue allocated to the class. We therefore find reasonable and adopt the rate structure for TOU-GS and TOU-GS-SOP to which Edison and PSD have agreed and direct the implementation of these schedules in the manner proposed by these parties. To ensure consistency with our other findings, however, no "ratcheting" of demand charges should be included in these schedules.

or no benefits since the rate would increase as billing parameters decreased.

Edison concludes therefore that SCRUB's proposal must be evaluated not just on the basis of the benefit, if any, received by schools, but whether all of Edison's customers would be positively or adversely affected. Due to the high administrative, metering, and billing costs, Edison believes that the final result of conjunctive billing will be an adverse impact on all other ratepayers.

While Edison has raised appropriate concerns regarding conjunctive billing, we do not believe that these concerns warrant our rejection of conjunctive billing for multiple meters at single school sites on an experimental basis. We continue to believe that this form of conjunctive billing, subject to the limitations imposed in D.86-12-091, will permit the schools to realize the benefit of consolidated billing without the need to incur any additional costs just to attain that goal. We also believe, however, that D.86-12-091 as well as Resolution E-3045 reflect our need to ensure that the asserted benefits of conjunctive billing are realized. As authorized in that resolution, PG&E's offering of conjunctive billing for schools is on a limited, experimental basis subject to an evaluation of the program in PG&E's next general rate case. This evaluation will examine conjunctive billing on the basis of its revenue effect, the need for its continuation for schools, and the need for its expansion to other customer groups.

For these reasons, we find that it is appropriate to order Edison to offer conjunctive billing for multiple meters at a single school site consistent with D.86-12-091 and Resolution E-3045. We will therefore require Edison to file an advice letter implementing the necessary tariffs or forms to accomplish this goal and to perform for its next general rate case an evaluation of

With respect to the sole issue in dispute, we find reasonable and adopt the energy charges for the two schedules as proposed by Edison. Edison has adequately demonstrated that these charges are required to ensure consistency and stability in rate levels and between rate schedules.

3. Issues Impacting School Districts

In this proceeding, SCRUB has requested consolidated or "conjunctive" billing at a single rate of all meters at a single school site and all meters within an entire school district. SCRUB also asks that the non-time related demand charge for distribution be waived for school districts if that district enters a formal agreement with Edison to limit energy usage during peak periods to a predetermined level. Edison opposes both of these recommendations.

a. Conjunctive Billing

Conjunctive billing for schools was addressed in PG&E's most recent general rate case. In D.86-12-091 in that proceeding, we found that it was reasonable for PG&E to provide schools taking service from more than one meter at the same site with the opportunity to have their total usage consolidated for billing purposes. (D.86-12-091, at pp. 81-82.) This same finding, however, was not extended to consolidated billing for multiple sites based on our conclusion that no distinction should be made between two or more customers taking service at individual sites and one customer taking service at multiple sites.

We therefore required PG&E to offer conjunctive billing for multiple meters at a single school, and in its next rate case, address the propriety of expanding conjunctive billing to all customers. (D.86-12-091, at p. 82.) Under the terms of that billing, the school was not to be required to pay for any special facilities needed to achieve consolidation of its bills, but it would be required to pay for the administrative and facilities conjunctive billing for schools and for all customers consistent with these decisions.

We are unpersuaded by SCRUB's arguments to extend conjunctive billing beyond the single school site. The reservations expressed by Edison regarding single site conjunctive billing already require that that program be instituted only on a limited basis. We do not believe that sufficient justification has been provided to enlarge that program to include conjunctive billing for multiple sites.

b. <u>Waiver of Non-Time-Related Demand Charges</u>

SCRUB also proposes that the non-time-related demand charge for distribution be waived for schools, if the school district enters a formal agreement with Edison to limit energy usage during peak periods to a predetermined level. SCRUB's request is based on the annual electrical usage pattern of schools and the flexibility which schools have in summer scheduling. According to SCRUB these factors create a unique opportunity to free electricity for use on the Edison system during peak times and save costs for both Edison and school districts. By adopting its recommendation, SCRUB testified that net marginal cost savings to Edison of $23.88 for each peak kw not used by a school and made available to the system would be realized.

Edison opposes SCRUB's proposal as unnecessary since the proposed rates applicable to schools are "unbundled" and already reflect the appropriate reduction in summer time-related demand charges. According to Edison, if a school has lower demands in summer months, this lower demand will be reflected in a reduced time-related demand charge. Edison asserts that this charge properly reflects the cost of distribution facilities which is determined by the highest demand occurring throughout the year. Edison therefore believes that to reduce the non-time-related portion of the demand charge would defeat the purpose of unbundling the rate.

costs associated with providing service on one site at different locations. (Id., at pp. 81-82.)

In response to D.86-12-091, PG&E filed an advice letter earlier this year seeking Commission approval of two new forms related to conjunctive billing for schools. Of these two billing forms, one reflected on the cost of allocated facilities necessary to provide service at multiple sites, while the other, a simpler form, involved combining meter readings from all accounts at a site and billing them under one rate. These forms were the result of an agreement between PG&E and SCRUB who had also agreed that the forms should be offered on a limited, experimental basis. Specifically, the parties agreed that, due to the costs and complexities of the facility cost agreement, this form would be offered on a test basis to a limited number of schools. The second, simpler option would be offered as a further experiment limited to primary and secondary schools.

By Resolution E-3045, dated August 26, 1987, PG&E was authorized to file these two new forms. The resolution also directed PG&E in its next general rate case to evaluate this conjunctive billing experiment on the basis, among other things, of its revenue effect, the need for its continuation, and the propriety of making the option available to other types of customers.

In this proceeding, as stated previously, SCRUB asks that Edison be required, as PG&E was, to undertake conjunctive billing for schools. SCRUB's request, however, includes not only conjunctive billing for all meters at a single school site, but also all meters at multiple sites within a single school district.

With respect to this latter request, SCRUB believes that conjunctive billing for multiple sites is required to permit the school district to practice load management and to accurately determine the economics of self-generation. SCRUB states that this type of billing could be undertaken by Edison on an experimental

As we have previously indicated, we have rejected Edison's proposal to ratchet demand charges. This conclusion is equally applicable to demand charges for schools

We concur with Edison, however, that "unbundled" and time-differentiated rates charged to schools are adequate to ensure that the schools pay those costs reasonably attributable to their usage characteristics. Any further refinement of the rates under which schools are provided service is therefore unnecessary at this time. SCRUB's recommended waiver for schools of non-time-related demand charges should therefore be rejected.

D. <u>Large Power Customer Group</u>

Edison's large power customer group receives service primarily under the mandatory time-of-use schedule, TOU-8. In addition to the TOU-8 schedule, these customers are offered optional time-of-use schedules providing interruptible and super-off-peak (SOP) rates and service, as well as real-time pricing. Additionally, standby service is provided to those customers who require backup service for their own generation facilities. In this proceeding, Edison has further proposed two contract rate options for this customer group.

Edison and PSD have reached substantial agreement on the rate structure for these schedules. Significant issues, however, remain between these two parties, as well as numerous interested parties including FEA, CMA, IU, CLECA/CSPG, DGS, and the CSC. The schedules and the positions of the parties are reviewed below followed by our resolution of each issue.

1. <u>TOU-8</u>

Edison and the PSD are in agreement with respect to virtually all aspects of the basic TOU-8 schedule with the exception of the development of the TOU-8 energy charges. Both Edison and PSD agree that in the event that the adopted revenue requirement is different from that upon which their proposed rate basis subject to certain conditions. These conditions would include (1) Edison's installation of the necessary equipment and implementation of the necessary billing procedures, (2) computation of the bill under the rate schedule that is applicable to the combined usage, and (3) recovery by Edison of the cost of any additional facilities and efforts related to conjunctive billing directly from the districts receiving the service in the form of predetermined, standard monthly service charges.

Edison states that it objects to conjunctive billing for schools for both single sites and multiple sites. Edison believes that conjunctive billing is not cost-effective, "bundles" rather than "unbundles" generation, transmission, and distribution costs; and is not a proper means of reflecting non-time related demand on its distribution system.

With respect to this latter point, Edison believes that inequities in rate design will result if the "benefit" of conjunctive billing is extended to one customer group. Specifically, Edison asserts that diversity among accounts is already recognized by virtue of the design billing parameters which are based on historical "noncoincident" demands. Edison states that as these billing parameters decrease under conjunctive billing, the demand charge must increase proportionately to recover Edison's cost of service. Edison therefore concludes that if only schools are permitted conjunctive billing, all other customers, other than schools, would be adversely affected. Edison notes, however, that conversely if all multiple-site customers were entitled to conjunctive billing, the concept would produce little or no benefits since the rate would increase as billing parameters decreased.

Edison concludes therefore that SCRUB's proposal must be evaluated not just on the basis of the benefit, if any, received by schools, but whether all of Edison's customers would be positively or adversely affected. Due to the high administrative, metering, design is based, the differences should be reflected in the energy, as opposed to demand, charges.

FEA, CMA, IU, and CLECA/CSPG have also provided testimony recommending energy and demand charges for the TOU-8 schedule. These parties state that their recommendations emphasize the need to implement cost-based rates for the TOU-8 schedules while preserving rate stability.

a. TOU-8 Rates By Voltage Level

In D.84-12-068 in Edison's last general rate case, the Commission adopted a two-step approach for revising the manner in which voltage differences within the TOU-8 customer group were recognized. The first step, which was taken in D.84-12-068, was to adopt PSD's voltage discounts for each of the three voltage categories of below 2 kV, 2 kV to 50 kV, and greater than 50 kV. The second step, which was to be taken in this proceeding, was the division of the TOU-8 rate schedules into the three voltage categories with rates based on marginal costs developed for each of those subgroups.

In this proceeding, PSD submitted a proposal to establish the three TOU-8 voltage levels as separate schedules. Edison, while first declining to recommend this approach, subsequently supported PSD's proposal. PSD's proposal was also supported by FEA and IU. PSD, FEA, and IU agree that separate rate schedules by voltage level yield rates which reflect the different costs of service imposed at each voltage level and the different load characteristics related to each of those levels.

We find that PSD's proposed TOU-8 subschedules are in keeping with our decision in Edison's last general rate case and provide rates related to the cost of service and load characteristics of TOU-8 customers by voltage level. This approach therefore further refines and improves the price signals which TOU-8 customers receive.

and billing costs, Edison believes that the final result of conjunctive billing will be an adverse impact on all other ratepayers.

While Edison has raised appropriate concerns regarding conjunctive billing, we do not believe that these concerns warrant our rejection of conjunctive billing for multiple meters at single school sites on an experimental basis. We continue to believe that this form of conjunctive billing, subject to the limitations imposed in D.86-12-091, will permit the schools to realize the benefit of consolidated billing without the need to incur any additional costs just to attain that goal. We also believe, however, that D.86-12-091 as well as Resolution E-3045 reflect our need to ensure that the asserted benefits of conjunctive billing are realized. As authorized in that resolution, PG&E's offering of conjunctive billing for schools is on a limited, experimental basis subject to an evaluation of the program in PG&E's next general rate case. This evaluation will examine conjunctive billing on the basis of its revenue effect, the need for its continuation for schools, and the need for its expansion to other customer groups.

For these reasons, we find that it is appropriate to order Edison to offer conjunctive billing for multiple meters at a single school site consistent with D.86-12-091 and Resolution E-3045. We will therefore require Edison to file an advice letter implementing the necessary tariffs or forms to accomplish this goal and to perform for its next general rate case an evaluation of conjunctive billing for schools and for all customers consistent with these decisions.

We are unpersuaded by SCRUB's arguments to extend conjunctive billing beyond the single school site. The reservations expressed by Edison regarding single site conjunctive billing already require that that program be instituted only on a limited basis. We do not believe that sufficient justification has

b. Demand Charges.

Agreement was also reached between Edison and PSD on all demand charges (time-related and non-time-related) for the large power customer group. Several interested parties, however, proposed different demand charges as well as "rate limiters" designed to avoid rate shock by certain customers. The issue of rate limiters is discussed in a separate section following our consideration of the TOU-8 schedule and other large power customer rate options. All parties state that their proposed demand charges are based on marginal costs.

(1) Parties Positions

Edison and PSD assert that the demand charges to which they have agreed best reflect marginal demand costs without producing adverse bill impacts. In the case of time-related demand charges, Edison and PSD have agreed to eliminate winter off-peak demand charges and to use the higher on-peak demand charges proposed by PSD. These demand charges are set at 50% of the marginal on-peak demand costs for the on-peak period, 100% of the marginal coincident demand costs for the mid-peak period, and zero for the off-peak period.

With regard to non-time-related demand charges, Edison and PSD reached a compromise position. Edison had proposed to base this charge on the highest demand in the previous year while PSD proposed that it be the highest demand for the month. The agreement provides for the non-time-related demand charge to be the highest demand for the month or 50% of the highest demand for the preceeding 11 months, whichever is greater. PSD believes that this approach will provide an incentive to customers to reduce demand while still ensuring rates which reflect the costs incurred by the utility to meet noncoincident demand.

FEA and IU endorse the agreement reached by PSD and Edison to differentiate between time-related and non-time-related demand charges. According to FEA, such a rate design approach been provided to enlarge that program to include conjunctive billing for multiple sites.

b. Waiver of Non-Time-Related Demand Charges

SCRUB also proposes that the non-time-related demand charge for distribution be waived for schools, if the school district enters a formal agreement with Edison to limit energy usage during peak periods to a predetermined level. SCRUB's request is based on the annual electrical usage pattern of schools and the flexibility which schools have in summer scheduling. According to SCRUB these factors create a unique opportunity to free electricity for use on the Edison system during peak times and save costs for both Edison and school districts. By adopting its recommendation, SCRUB testified that net marginal cost savings to Edison of $23.88 for each peak kw not used by a school and made available to the system would be realized.

Edison opposes SCRUB's proposal as unnecessary since the proposed rates applicable to schools are "unbundled" and already reflect the appropriate reduction in summer time-related demand charges. According to Edison, if a school has lower demands in summer months, this lower demand will be reflected in a reduced time-related demand charge. Edison asserts that this charge properly reflects the cost of distribution facilities which is determined by the highest demand occurring throughout the year. Edison therefore believes that to reduce the non-time-related portion of the demand charge would defeat the purpose of unbundling the rate.

As we have previously indicated, we have rejected Edison's proposal to ratchet demand charges. This conclusion is equally applicable to demand charges for schools

We concur with Edison, however, that "unbundled" and time-differentiated rates charged to schools are adequate to ensure that the schools pay those costs reasonably attributable to their usage characteristics. Any further refinement of the rates under permits rates to reflect more accurately cost differences across time periods.

According to IU, the shift of fixed costs from the energy charge to demand charge components of the TOU-8 rate schedule should be subject only to the limitation that this change not result in adverse rate impacts. According to IU, a full implementation of EPMC for these rate components could produce unacceptably severe bill impacts for low load factor and seasonal customers because of the extremely high costs associated with summer peak demand.

To offset this result, IU proposes that the on-peak demand charge be set at 50% of the EPMC level if the Commission approves the revenue requirement proposed by Edison. In the case of PSD's proposed revenue decrease, IU acknowledges that adverse rate impacts will be less significant and proposes that the peak demand charge be set at 60% of EPMC.

As a means of recovering the remaining on-peak demand costs, IU proposes that the winter demand charge not be eliminated as recommended by PSD and Edison, but be retained at that its present level in order to recover a portion of the demand costs not recovered in the peak demand charges. Alternatively, IU recommends that the balance of unrecovered on-peak demand costs be recovered in the on-peak energy charges to ensure recovery of those costs in the same time period during which they are incurred. IU emphasizes that this approach would be merely temporary until class revenues move closer to cost in future rate proceedings. To the extent that severe bill impacts may occur despite such a demand charge limitation, IU proposes that the Commission consider and adopt "rate limiters."

CMA proposes, consistent with its marginal demand cost recommendation that demand charges should be based on the use of Edison's adopted Energy Reliability Index (ERI). The ERI, as explained earlier in this decision, is used in adjusting capacity which schools are provided service is therefore unnecessary at this time. SCRUB's recommended waiver for schools of non-time-related demand charges should therefore be rejected.

D. Large Power Customer Group

Edison's large power customer group receives service primarily under the mandatory time-of-use schedule, TOU-8. In addition to the TOU-8 schedule, these customers are offered optional time-of-use schedules providing interruptible and super-off-peak (SOP) rates and service, as well as real-time pricing. Additionally, standby service is provided to those customers who require backup service for their own generation facilities. In this proceeding, Edison has further proposed two contract rate options for this customer group.

Edison and PSD have reached substantial agreement on the rate structure for these schedules. Significant issues, however, remain between these two parties, as well as numerous interested parties including FEA, CMA, IU, CLECA/CSPG, DGS, and the CSC. The schedules and the positions of the parties are reviewed below followed by our resolution of each issue.

1. TOU-8

Edison and the PSD are in agreement with respect to virtually all aspects of the basic TOU-8 schedule with the exception of the development of the TOU-8 energy charges. Both Edison and PSD agree that in the event that the adopted revenue requirement is different from that upon which their proposed rate design is based, the differences should be reflected in the energy, as opposed to demand, charges.

FEA, CMA, IU, and CLECA/CSPG have also provided testimony recommending energy and demand charges for the TOU-8 schedule. These parties state that their recommendations emphasize the need to implement cost-based rates for the TOU-8 schedules while preserving rate stability.

values for QF pricing and in undertaking resource cost-effectiveness analyses. According to CMA, inclusion of the ERI in the calculation of demand charges will provide recognition of the existing oversupply of generation capacity. Based on its calculations, CMA also believes that introduction of the ERI into the demand charge determination would have the additional, desirable result of reducing the problem of rate shock which would exist if full EPMC rates were charged.

PSD opposes CMA's recommendation to apply the ERI to customer demand charges. PSD notes that the use of the ERI, used to adjust short-run marginal costs, would fail to reflect the long-term costs of the system. PSD asserts that use of the ERI would therefore prevent TOU-8 demand charges from reflecting accurate, long-term price signals on which customers could base their investment decisions and changes in production patterns.

CMA also requests that TOU-8 rates should not include a "ratchet" on maximum demand charges. The "ratchet" to which CMA refers relates to Edison's and PSD's agreement to set non-time-related demand charges at 50% of the highest demand over the previous eleven months. CMA notes that while PSD had proposed no ratchet at all originally, it compromised with Edison by agreeing to a ratchet of 50% of the highest demand over the previous eleven months. CMA submits that PSD's original position was correct and that a ratchet of any amount on a noncoincident demand charge fails to reflect costs or provide proper price signal to customers.

In response to CMA, Edison states that the proposed ratchet on demand charges is necessary to ensure Edison's recovery of the cost of distribution facilities. According to Edison, these costs are a function of the capacity of the distribution facilities installed for each customer, which capacity is defined by the customer's highest demand regardless of when it occurs. Edison

a. TOU-8 Rates By Voltage Level

In D.84-12-068 in Edison's last general rate case, the Commission adopted a two-step approach for revising the manner in which voltage differences within the TOU-8 customer group were recognized. The first step, which was taken in D.84-12-068, was to adopt PSD's voltage discounts for each of the three voltage categories of below 2 kV, 2 kV to 50 kV, and greater than 50 kV. The second step, which was to be taken in this proceeding, was the division of the TOU-8 rate schedules into the three voltage categories with rates based on marginal costs developed for each of those subgroups.

In this proceeding, PSD submitted a proposal to establish the three TOU-8 voltage levels as separate schedules. Edison, while first declining to recommend this approach, subsequently supported PSD's proposal. PSD's proposal was also supported by FEA and IU. PSD, FEA, IU, and CLECA/CSPG agree that separate rate schedules by voltage level yield rates which reflect the different costs of service imposed at each voltage level and the different load characteristics related to each of those levels.

We find that PSD's proposed TOU-8 subschedules are in keeping with our decision in Edison's last general rate case and provide rates related to the cost of service and load characteristics of TOU-8 customers by voltage level. This approach therefore further refines and improves the price signals which TOU-8 customers receive.

b. Demand Charges.

Agreement was also reached between Edison and PSD on all demand charges (time-related and non-time-related) for the large power customer group. Several interested parties, however, proposed different demand charges as well as "rate limiters" designed to avoid rate shock by certain customers. The issue of rate limiters is discussed in a separate section following our consideration of the TOU-8 schedule and other large power customer states that a 12-month ratchet ensures that seasonal variations in monthly demands do not distort the appropriate price signal.

Edison also asserts that non-time-related demand charges are not designed to recover coincident demand related costs and are therefore not intended to reflect diversity. Edison further does not believe that noncoincident demand costs should be collected through energy rates a result which would occur in the absence of a ratchet. Edison states that, absent its compromise with PSD for a 50% ratchet, it would have continued to support a 100% ratchet.

(2) Discussion

We find that Edison's and PSD's agreement, for the most part, achieves demand charges which are cost-based and load-related. We do not concur, however, with Edison's and PSD's compromise on "ratcheting" of demand charges nor with the IU's suggestion of setting the demand charge at less than EPMC. Neither of these recommendations achieve our goal of providing cost-based rates and ensuring accurate price signals to the affected customer group.

With respect to ratchets, the Commission in recent years has sought to move away from this concept. For PG&E ratchets were used only for certain agricultural schedules. The reason for this policy is clear. Specifically, ratchets have an inequitable effect on many customers. Customers with stable levels of demand throughout the year would not be greatly affected by ratchets, but seasonal industries would see their off-season energy bills increase even though their off-season demand and energy usage would be relatively low. The ultimate effect could be discrimination in customer billings among customers with identical usage.

We believe that such a result is almost completely at odds with our efforts to accurately reflect the costs imposed by the customer on a time- and load-related basis.and would require significant justification on the part of the party proposing the rate options. All parties state that their proposed demand charges are based on marginal costs.

(1) Parties Positions

Edison and PSD assert that the demand charges to which they have agreed best reflect marginal demand costs without producing adverse bill impacts. In the case of time-related demand charges, Edison and PSD have agreed to eliminate winter off-peak demand charges and to use the higher on-peak demand charges proposed by PSD. These demand charges are set at 50% of the marginal on-peak demand costs for the on-peak period, 100% of the marginal coincident demand costs for the mid-peak period, and zero for the off-peak period.

With regard to non-time-related demand charges, Edison and PSD reached a compromise position. Edison had proposed to base this charge on the highest demand in the previous year while PSD proposed that it be the highest demand for the month. The agreement provides for the non-time-related demand charge to be the highest demand for the month or 50% of the highest demand for the preceeding 11 months, whichever is greater. PSD believes that this approach will provide an incentive to customers to reduce demand while still ensuring rates which reflect the costs incurred by the utility to meet noncoincident demand.

FEA and IU endorse the agreement reached by PSD and Edison to differentiate between time-related and non-time-related demand charges. According to FEA, such a rate design approach permits rates to reflect more accurately cost differences across time periods.

According to IU, the shift of fixed costs from the energy charge to demand charge components of the TOU-8 rate schedule should be subject only to the limitation that this change not result in adverse rate impacts. According to IU, a full implementation of EPMC for these rate components could produce unacceptably severe bill impacts for low load factor and seasonal ratchet. We have carefully reviewed the proposal of Edison and PSD and Edison's arguments in support of the ratchet and do not find the level of justification required to adopt this approach.

Additionally, we also do not rule out the possibility, despite Edison's argument to the contrary, that diversity in demand is reflected in non-time-related demand charges over a 12-month period, a time frame which even Edison used to ensure no distortions in the price signal due to seasonal variations in demand.

Any resulting allocation of non-time-related demand costs to energy charges, as opposed to demand charges, due to the absence of the ratchet is not a sufficient reason to impose ratchets. While we seek to "unbundle" and correctly identify costs with the appropriate rate component, this effort should not be blind to detrimental impacts which may result. We therefore reject Edison's and PSD's imposition of ratchets on all demand-related meters for small, medium, and large power customer rate schedules.

We also do not believe it is appropriate to limit demand charges to a certain percentage of their EPMC level. In an effort to achieve cost-based rates, we believe that each individual rate component should be based, to the extent possible, on marginal cost. If adverse impacts should result due to following this approach, we can, to the extent required, consider rate limiters which we believe maintain the proper price signal while affording relief from such impacts. The topic of rate limiters, as stated previously, is discussed later in this section.

Finally, we turn to the suggestion of CMA to apply the ERI to the calculation of the demand charge. Earlier in this decision, we rejected CMA's proposal that generation marginal demand costs should reflect the ERI. We found that further evidence was required to determine whether the concerns which lead to the adoption of an ERI to adjust QF capacity prices in the customers because of the extremely high costs associated with summer peak demand.

To offset this result, IU proposes that the on-peak demand charge be set at 50% of the EPMC level if the Commission approves the revenue requirement proposed by Edison. In the case of PSD's proposed revenue decrease, IU acknowledges that adverse rate impacts will be less significant and proposes that the peak demand charge be set at 60% of EPMC.

As a means of recovering the remaining on-peak demand costs, IU proposes that the winter demand charge not be eliminated as recommended by PSD and Edison, but be retained at that its present level in order to recover a portion of the demand costs not recovered in the peak demand charges. Alternatively, IU recommends that the balance of unrecovered on-peak demand costs be recovered in the on-peak energy charges to ensure recovery of those costs in the same time period during which they are incurred. IU emphasizes that this approach would be merely temporary until class revenues move closer to cost in future rate proceedings. To the extent that severe bill impacts may occur despite such a demand charge limitation, IU proposes that the Commission consider and adopt "rate limiters."

CMA proposes, consistent with its marginal demand cost recommendation that demand charges should be based on the use of Edison's adopted Energy Reliability Index (ERI). The ERI, as explained earlier in this decision, is used in adjusting capacity values for QF pricing and in undertaking resource cost-effectiveness analyses. According to CMA, inclusion of the ERI in the calculation of demand charges will provide recognition of the existing oversupply of generation capacity. Based on its calculations, CMA also believes that introduction of the ERI into the demand charge determination would have the additional, desirable result of reducing the problem of rate shock which would exist if full EPMC rates were charged.

short-run were the same as for the calculation of marginal costs used in revenue allocation and rate design.

This finding reflects our concern, as even PSD has noted, that the purpose for which the ERI was developed and is currently being used may not be applicable to designing rates. We have directed Edison and PSD to examine the issue of the propriety of reflecting the ERI adjustment in generation marginal demand costs in Edison's next general rate case. We will similarly direct Edison to consider its applicability for rate design purposes as well.

c. Energy Charges

The only area of significant disagreement between PSD and Edison with respect to the TOU-8 schedule relates to the energy charge component of that schedule. CLECA/CSPG, FEA, and IU also provided testimony and argument on this issue.

Edison proposes to set the off-peak energy charge at 5 cents/kWh with the on- and mid-peak energy rates set to collect the remaining revenue requirement and to reflect marginal energy cost ratios. Edison states that its off-peak proposal is designed to reflect marginal costs as closely as possible while mitigating adverse bill impacts for some customers. In Edison's opinion, the 5-cent level provides a stable off-peak rate, making it easier, for customers to make appropriate investment decisions.

In contrast, PSD recommends that the off-peak energy rate be set at the full EPMC level. PSD further proposes that the balance of the revenue requirement for this class, including the marginal costs for the on- and mid-peak periods and the residual demand marginal costs not collected from the demand charges, should be recovered through the remaining energy charges.

In Edison's view, PSD's proposal places too much reliance on current marginal cost relationships and in turn fails to recognize the need for stability and consistency in rates. Further, according to Edison, PSD's proposal results in allocating

PSD opposes CMA's recommendation to apply the ERI to customer demand charges. PSD notes that the use of the ERI, used to adjust short-run marginal costs, would fail to reflect the long-term costs of the system. PSD asserts that use of the ERI would therefore prevent TOU-8 demand charges from reflecting accurate, long-term price signals on which customers could base their investment decisions and changes in production patterns.

CMA also requests that TOU-8 rates should not include a "ratchet" on maximum demand charges. The "ratchet" to which CMA refers relates to Edison's and PSD's agreement to set non-time-related demand charges at 50% of the highest demand over the previous eleven months. CMA notes that while PSD had proposed no ratchet at all originally, it compromised with Edison by agreeing to a ratchet of 50% of the highest demand over the previous eleven months. CMA submits that PSD's original position was correct and that a ratchet of any amount on a noncoincident demand charge fails to reflect costs or provide proper price signal to customers.

In response to CMA, Edison states that the proposed ratchet on demand charges is necessary to ensure Edison's recovery of the cost of distribution facilities. According to Edison, these costs are a function of the capacity of the distribution facilities installed for each customer, which capacity is defined by the customer's highest demand regardless of when it occurs. Edison states that a 12-month ratchet ensures that seasonal variations in monthly demands do not distort the appropriate price signal.

Edison also asserts that non-time-related demand charges are not designed to recover coincident demand related costs and are therefore not intended to reflect diversity. Edison further does not believe that noncoincident demand costs should be collected through energy rates a result which would occur in the absence of a ratchet. Edison states that, absent its compromise all uncollected capacity costs to the on- and mid-peak period energy rates based on loss of load probabilities (LOLP). Edison states that this approach will result in an overstatement of on-peak costs and an understatement of off-peak costs which in turn could encourage uneconomic on-peak bypass.

In taking issue with Edison's approach, PSD asserts that Edison's number is not based on a formula, but is apparently intended to provide a stable round number as a base and to ensure some contribution to margin. PSD states that the problem with Edison's "stable" rate is that it may make too much contribution to margin and will act as a disincentive for customers to shift off peak. This result, according to PSD, conflicts with Edison's with its minimum load concerns.

CLECA/CSPG support PSD's proposed off-peak rate. CLECA/CSPG state that this rate is cost-based, is consistent with PSD's EPMC allocation methodology, and results in relatively low off-peak rates encouraging off-peak consumption. CLECA/CSPG share PSD's concerns that Edison's 5 cent off-peak energy rate is not cost-justified and may discourage desirable incremental sales in the off-peak period. CLECA/CSPG note that Edison has admitted that this off-peak energy rate is well in excess of marginal energy cost and that its justification for the rate is based only on its potential for stability and mitigation of adverse bill impacts.

FEA asserts that cost-based rates require that demand costs be collected through demand charges and energy costs through energy charges. FEA therefore recommends removing demand costs from off-peak and mid-peak energy charges and setting those charges at marginal cost. Because customer impact considerations do require gradual movement toward cost-based rates in some instances, however, FEA also recommends that rates for primary and secondary customers be set to collect a portion of the demand costs through on-peak energy charge.

with PSD for a 50% ratchet, it would have continued to support a 100% ratchet.

(2) Discussion

We find that Edison's and PSD's agreement, for the most part, achieves demand charges which are cost-based and load-related. We do not concur, however, with Edison's and PSD's compromise on "ratcheting" of demand charges nor with the IU's suggestion of setting the demand charge at less than EPMC. Neither of these recommendations achieve our goal of providing cost-based rates and ensuring accurate price signals to the affected customer group. While we understand that IU's proposal was intended solely as a temporary, transitional device to mitigate adverse rate impacts, we believe, as explained below, that the use of rate limiters is a more appropriate means of achieving this goal.

With respect to ratchets, the Commission in recent years has sought to move away from this concept. For PG&E ratchets were used only for certain agricultural schedules. The reason for this policy is clear. Specifically, ratchets have an inequitable effect on many customers. Customers with stable levels of demand throughout the year would not be greatly affected by ratchets, but seasonal industries would see their off-season energy bills increase even though their off-season demand and energy usage would be relatively low. The ultimate effect could be discrimination in customer billings among customers with identical usage.

We believe that such a result is almost completely at odds with our efforts to accurately reflect the costs imposed by the customer on a time- and load-related basis and would require significant justification on the part of the party proposing the ratchet. We have carefully reviewed the proposal of Edison and PSD and Edison's arguments in support of the ratchet and do not find the level of justification required to adopt this approach.

Additionally, we also do not rule out the possibility, despite Edison's argument to the contrary, that

IU recommends that the on-peak energy charge include on-peak demand costs only as an alternative means of recovering those demand costs not recovered under IU's proposal for demand charges to be set at a percentage of EPMC. IU notes that this approach is only temporary until a full EPMC revenue allocation is achieved and that otherwise IU supports the recovery of fixed costs in demand charges.

We find reasonable and adopt Edison's proposed off-peak energy charges. This step is necessary to ensure consistency between the TOU-8 and TOU-GS schedules and to mitigate any adverse effect which might result from customers having to change schedules.

2. <u>Rate Options</u>

In this proceeding, several rate options were proposed by Edison and PSD for customers served under the TOU-8 rate schedule. These options include a super-off-peak (SOP) option, various interruptible options, two separate contract rate options, and a real-time pricing option. The parties also focused on changes to standby rates offered for backup service to those customers with their own generation facilities. In addition, to Edison and PSD, numerous interested parties responded to these proposals and offered their own recommendations. The parties' positions on each of these options is reviewed below followed by our discussion and resolution of each of the issues presented.

a. <u>Real Time Pricing</u>

Real time pricing is an experimental program designed to provide innovative ways in which customers can respond to costing periods which are more narrowly defined than the normal time-of-use periods. In this proceeding, PSD has proposed schedule RTP (real time pricing). Edison has agreed to accept PSD's hourly marginal costing and rate design methodologies for this proposed schedule, and both parties have agreed to the phase-in methodology and program expansion rate related to its implementation.

diversity in demand is reflected in non-time-related demand charges over a 12-month period, a time frame which even Edison used to ensure no distortions in the price signal due to seasonal variations in demand.

Any resulting allocation of non-time-related demand costs to energy charges, as opposed to demand charges, due to the absence of the ratchet is not a sufficient reason to impose ratchets. While we seek to "unbundle" and correctly identify costs with the appropriate rate component, this effort should not be blind to detrimental impacts which may result. We therefore reject Edison's and PSD's imposition of ratchets on all demand-related meters for small, medium, and large power customer rate schedules.

As previously stated, we also do not believe it is appropriate to limit demand charges to a certain percentage of their EPMC level. In an effort to achieve cost-based rates, we believe that each individual rate component should be based, to the extent possible, on marginal cost. If adverse impacts should result due to following this approach, we believe that rate limiters, discussed later in this section, provide a more appropriate mechanism to offset those impacts while maintaining proper price signals.

Finally, we turn to the suggestion of CMA to apply the ERI to the calculation of the demand charge. Earlier in this decision, we rejected CMA's proposal that generation marginal demand costs should reflect the ERI. We found that further evidence was required to determine whether the concerns which lead to the adoption of an ERI to adjust QF capacity prices in the short-run were the same as for the calculation of marginal costs used in revenue allocation and rate design.

This finding reflects our concern, as even PSD has noted, that the purpose for which the ERI was developed and is currently being used may not be applicable to designing rates. We have directed Edison and PSD to examine the issue of the propriety

PSD states that the real time pricing periods reflected in the RTP schedule represent times when the utility system is often most strained. PSD believes that the real time pricing program will therefore not only permit customers to dramatically increase their control over their energy costs, but also enable the utility to reduce its costs.

We find that PSD's real-time pricing proposal is reasonable and should be adopted. The experimental program designed by PSD achieves the program goals of providing more specific price signals than are available under current time-of-use rates which will in turn serve to control both customer and utility costs.

b. Schedule TOU-8-SOP

In addition to its real-time-pricing proposal, PSD in this proceeding also proposed a TOU-8 schedule with super-off-peak (SOP) rates. According to PSD, SOP rates are closely related to real time pricing, establishing an additional time of use period during which energy rates are lowered below the off-peak rate. PSD believes that this rate structure provides an opportunity for Edison to address its minimum load "problem" by providing customers with an incentive to move their consumption to the SOP periods. Edison generally agrees with PSD's TOU-8-SOP rate proposal, including the redefined TOU periods and proposed rate structure.

The only difference between the parties is the method which each has used to estimate the number of customers who will move from TOU-8 to TOU-8 SOP and the revenue shortfall which will in turn result. Edison estimates approximately 730 customers will have the incentive to move to the TOU-8 SOP rate with a resulting revenue shortfall of $12.7 million. PSD estimates approximately 125 customers will be likely to change schedules based on the criterion of requiring a customer's rates to improve by 5% before assuming that a change would be made. This difference impacts the exact rates to be charged TOU-8-SOP customers since the parties of reflecting the ERI adjustment in generation marginal demand costs in Edison's next general rate case. We will similarly direct Edison to consider its applicability for rate design purposes as well.

c. Energy Charges

The only area of significant disagreement between PSD and Edison with respect to the TOU-8 schedule relates to the energy charge component of that schedule. CLECA/CSPG, FEA, and IU also provided testimony and argument on this issue.

Edison proposes to set the off-peak energy charge at 5 cents/kWh with the on- and mid-peak energy rates set to collect the remaining revenue requirement and to reflect marginal energy cost ratios. Edison states that its off-peak proposal is designed to reflect marginal costs as closely as possible while mitigating adverse bill impacts for some customers. In Edison's opinion, the 5-cent level provides a stable off-peak rate, making it easier, for customers to make appropriate investment decisions.

In contrast, PSD recommends that the off-peak energy rate be set at the full EPMC level. PSD further proposes that the balance of the revenue requirement for this class, including the marginal costs for the on- and mid-peak periods and the residual demand marginal costs not collected from the demand charges, should be recovered through the remaining energy charges.

In Edison's view, PSD's proposal places too much reliance on current marginal cost relationships and in turn fails to recognize the need for stability and consistency in rates. Further, according to Edison, PSD's proposal results in allocating all uncollected capacity costs to the on- and mid-peak period energy rates based on loss of load probabilities (LOLP). Edison states that this approach will result in an overstatement of on-peak costs and an understatement of off-peak costs which in turn could encourage uneconomic on-peak bypass.

agree that the revenue deficiency would be added to the demand and energy charges of the large power customer group on an EPMC basis.

PSD states that its method was based on estimating, through multiple iterations, which customers would choose each schedule and designing both TOU-SOP and TOU-8 schedules around the assigned customer group. Edison states that under its approach, a first iteration TOU-8-SOP rate based on marginal cost was designed and the revenue deficiency resulting from the migration of customers to this hypothetical schedule was determined. A second iteration of the rate was then designed to recover this revenue deficiency.

Edison believes that PSD's methodology is unnecessarily complex, involving multiple iterations to achieve a "stable" level of customers benefitting from the schedule, and results in a TOU-8-SOP rate that is too high to attract a reasonable number of customers. Under Edison's methodology, 98 TOU customers will benefit by more than 5% of their TOU-8 bill for a total benefit (or shortfall) of approximately $6 million. Under PSD's methodology, Edison states that the option would be attractive to a maximum of 48 TOU-8 customers which if all selected the PSD's rate option would produce approximately a $1.6 million revenue deficiency. PSD charges that Edison's approach is based on a simpler method which has little theoretical basis and only by coincidence achieves similar rates.

CLECA/CSPG support PSD's proposed TOU-8-SOP schedule. CLECA/CSPG finds a multitude of benefits from this schedule including providing opportunities for customers to respond to changes in utility costs, greater certainty than real time pricing, and stimulation of sales in the super-off-peak period. CLECA/CSPG also believe that the schedule will provide benefits to all customers in the form of increased sales, the prevention of uneconomic bypass, the building of customer satisfaction, and the

In taking issue with Edison's approach, PSD asserts that Edison's number is not based on a formula, but is apparently intended to provide a stable round number as a base and to ensure some contribution to margin. PSD states that the problem with Edison's "stable" rate is that it may make too much contribution to margin and will act as a disincentive for customers to shift off peak. This result, according to PSD, conflicts with Edison's with its minimum load concerns.

CLECA/CSPG support PSD's proposed off-peak rate. CLECA/CSPG state that this rate is cost-based, is consistent with PSD's EPMC allocation methodology, and results in relatively low off-peak rates encouraging off-peak consumption. CLECA/CSPG share PSD's concerns that Edison's 5 cent off-peak energy rate is not cost-justified and may discourage desirable incremental sales in the off-peak period. CLECA/CSPG note that Edison has admitted that this off-peak energy rate is well in excess of marginal energy cost and that its justification for the rate is based only on its potential for stability and mitigation of adverse bill impacts.

FEA asserts that cost-based rates require that demand costs be collected through demand charges and energy costs through energy charges. FEA therefore recommends removing demand costs from off-peak and mid-peak energy charges and setting those charges at marginal cost. Because customer impact considerations do require gradual movement toward cost-based rates in some instances, however, FEA also recommends that rates for primary and secondary customers be set to collect a portion of the demand costs through on-peak energy charge.

IU recommends that the on-peak energy charge include on-peak demand costs only as an alternative means of recovering those demand costs not recovered under IU's proposal for demand charges to be set at a percentage of EPMC. IU notes that this approach is only temporary until a full EPMC revenue allocation is achieved and reduction in the need for Edison to negotiate separate contract rates with its customers.

The need for a TOU-8-SOP rate option is clear. This option is another step toward cost-based rates which provide customers with the most accurate price signals regarding their use and an opportunity to change those usage patterns to reduce costs. Edison has indicated that it is also assisted by such a schedule as it encourages consumption and increases sales in the off-peak period thereby offsetting any minimum load "problem" which it might experience.

We have reviewed the methods by which Edison and PSD have attempted to estimate the number of customers who will migrate from the TOU-8 schedule to TOU-8-SOP and find a significant difference between these estimates. We believe that PSD's approach, which was based on several refinements of its estimate, may provide a more accurate and conservative basis for determining the estimated change. We are reluctant to require that the large customer group shoulder a significant revenue deficiency without a greater degree of assurance that this level of migration will result. We therefore adopt as reasonable PSD's proposed TOU-8-SOP time periods, rate structure, and rates.

c. <u>Interruptible Rates</u>

Interruptible rates have been available as options to Edison customers for some time. These schedules allow a customer who has less need for guaranteed service reliability to receive a lower rate in exchange for interruptions in his service. These lower rates appear as discounts provided under the interruptible schedules.

Edison has several existing interruptible schedules, I-1 through I-5. These schedules vary with the size of qualifying customer, the required degree of notice for interruption, and other factors. In this proceeding, Edison originally proposed that its interruptible schedules should remain unchanged with the exception that otherwise IU supports the recovery of fixed costs in demand charges.

We find reasonable and adopt Edison's proposed off-peak energy charges. This step is necessary to ensure consistency between the TOU-8 and TOU-GS schedules and to mitigate any adverse effect which might result from customers having to change schedules. In developing the TOU-8 rates, the interruptible credits are allocated on an incurrence, rather than an EPMC, basis. Further, to ensure that subtransmission voltage energy rates are not nominally higher than primary voltage energy rates, these rates are aligned to be equal.

2. Rate Options

In this proceeding, several rate options were proposed by Edison and PSD for customers served under the TOU-8 rate schedule. These options include a super-off-peak (SOP) option, various interruptible options, two separate contract rate options, and a real-time pricing option. The parties also focused on changes to standby rates offered for backup service to those customers with their own generation facilities. In addition, to Edison and PSD, numerous interested parties responded to these proposals and offered their own recommendations. The parties' positions on each of these options is reviewed below followed by our discussion and resolution of each of the issues presented.

a. Real Time Pricing

Real time pricing is an experimental program designed to provide innovative ways in which customers can respond to costing periods which are more narrowly defined than the normal time-of-use periods. In this proceeding, PSD has proposed schedule RTP (real time pricing). Edison has agreed to accept PSD's hourly marginal costing and rate design methodologies for this proposed schedule, and both parties have agreed to the phase-in methodology and program expansion rate related to its implementation.

of closing I-4, a recommendation to which PSD agreed due to the lack of use of this schedule by interruptible customers. In its testimony, however, PSD proposed the closing of Schedules I-2, I-3, and I-5 to new customers and the establishment of a new schedule, I-6. Schedule I-1 is already closed to new customers.

(1) Parties Positions

PSD asserts that the interruptible discounts should be based on the value of the system capacity at the time of interruption. PSD states that the present interruptible schedules are not cost-based. PSD therefore proposes that the I-2, I-3, and I-5 schedules be closed and that the new schedule I-6 be established.

The newly proposed schedule, I-6, is described by PSD as being similar to TOU-8, but with four time periods instead of three. The four would include three regular time periods like those included in TOU-8 and reflect the applicable unbundled components of system savings, i.e., energy and demand. PSD states that demand charges in these periods would be adjusted by the same ERI used to adjust QF capacity payments in order to reflect the value of the demand reduced by these interruptible customers.

PSD states that the fourth time period which it established in Schedule I-6 represents the 40 hours in the summer which are most likely to experience a call for interruption based on loss of load probabilities (LOLP). PSD states that a failure to interrupt when requested during those periods would lead to a penalty rate being imposed. PSD has based this penalty on the value of the service at the time of the interruption request. Under the I-6 schedule, PSD has also provided that customers could, as with I-3 and I-5, choose to designate a level of firm demand not subject to interruption. PSD states that its proposed I-6 schedule would allow a customer to select either immediate interruptibility or 1-hour notice. I-6 would be available to standby customers, PSD states that the real time pricing periods reflected in the RTP schedule represent times when the utility system is often most strained. PSD believes that the real time pricing program will therefore not only permit customers to dramatically increase their control over their energy costs, but also enable the utility to reduce its costs.

We find that PSD's real-time pricing proposal is reasonable and should be adopted. The experimental program designed by PSD achieves the program goals of providing more specific price signals than are available under current time-of-use rates which will in turn serve to control both customer and utility costs.

b. Schedule TOU-8-SOP

In addition to its real-time-pricing proposal, PSD in this proceeding also proposed a TOU-8 schedule with super-off-peak (SOP) rates. According to PSD, SOP rates are closely related to real time pricing, establishing an additional time of use period during which energy rates are lowered below the off-peak rate. PSD believes that this rate structure provides an opportunity for Edison to address its minimum load "problem" by providing customers with an incentive to move their consumption to the SOP periods. Edison generally agrees with PSD's TOU-8-SOP rate proposal, including the redefined TOU periods and proposed rate structure.

The only difference between the parties is the method which each has used to estimate the number of customers who will move from TOU-8 to TOU-8 SOP and the revenue shortfall which will in turn result. Edison estimates approximately 730 customers will have the incentive to move to the TOU-8 SOP rate with a resulting revenue shortfall of $12.7 million. PSD estimates approximately 125 customers will be likely to change schedules based on the criterion of requiring a customer's rates to improve by 5% before assuming that a change would be made. This difference impacts the exact rates to be charged TOU-8-SOP customers since the parties including cogenerators for whom current Schedules I-3 or I-5 are not available.

During hearings in this proceeding, Edison also endorsed the concept of an I-6 schedule. Edison, however, differed with PSD with respect to assumptions relating to the period of time during which the value of future capacity is to be discounted, the basis on which capacity is to be valued, and the choice of ERI to be applied to that discount. Edison states that the ERI assumption is critical since interruptible rates are highly sensitive to that assumption.

With respect to Edison's assumptions, PSD particularly objects to Edison having based the value of capacity on the marginal cost of generation only. In contrast, PSD states that it has based this value on the marginal costs of generation, transmission, and distribution.

Interested parties to this proceeding generally supported the establishment of an I-6 schedule. Among these parties, CLECA/ CSPG believes that PSD's proposed I-6 is a viable new interruptible rate option whose design is more directly tied to the overall large power rate design than is the current interruptible rate design. Edison's proposed I-6 schedule is flawed, in CLECA/CSPG's view, for its failure to consider the value of saved transmission and distribution capacity valuing interruptibility to utilities.

CMA believes, however, that interruptible rates should be based on the cost of serving the interruptible customer and not the value of curtailability in an excess capacity situation. For a cost-based interruptible rate, CMA states that the existence or non-existence of excess generation capacity is irrelevant and that those rates must ultimately reflect a cost, and not a value, analysis. Because such a cost analysis was not presented in this proceeding, CMA asks the Commission to consider such cost issues in the future.

agree that the revenue deficiency would be added to the demand and energy charges of the large power customer group on an EPMC basis.

PSD states that its method was based on estimating, through multiple iterations, which customers would choose each schedule and designing both TOU-SOP and TOU-8 schedules around the assigned customer group. Edison states that under its approach, a first iteration TOU-8-SOP rate based on marginal cost was designed and the revenue deficiency resulting from the migration of customers to this hypothetical schedule was determined. A second iteration of the rate was then designed to recover this revenue deficiency.

Edison believes that PSD's methodology is unnecessarily complex, involving multiple iterations to achieve a "stable" level of customers benefitting from the schedule, and results in a TOU-8-SOP rate that is too high to attract a reasonable number of customers. Under Edison's methodology, 98 TOU customers will benefit by more than 5% of their TOU-8 bill for a total benefit (or shortfall) of approximately $6 million. Under PSD's methodology, Edison states that the option would be attractive to a maximum of 48 TOU-8 customers which if all selected the PSD's rate option would produce approximately a $1.6 million revenue deficiency. PSD charges that Edison's approach is based on a simpler method which has little theoretical basis and only by coincidence achieves similar rates.

CLECA/CSPG support PSD's proposed TOU-8-SOP schedule. CLECA/CSPG finds a multitude of benefits from this schedule including providing opportunities for customers to respond to changes in utility costs, greater certainty than real time pricing, and stimulation of sales in the super-off-peak period. CLECA/CSPG also believe that the schedule will provide benefits to all customers in the form of increased sales, the prevention of uneconomic bypass, the building of customer satisfaction, and the

CMA also asserts that while penalties should exist for failures to curtail or interrupt, those penalties should be reasonable. In CMA's opinion, the existing graduated penalty provisions of Schedule I-5, adjusted to the amount of interruptible discount provided in the I-6 schedule, should be fully adequate. The concept of an escalating penalty is, in CMA's view, far more reasonable than PSD's and Edison's proposal to eliminate the discount ($33/kw/year for Edison and $80.80/kW/year for PSD) for a single failure to curtail. CMA also argues that subsequent failures using this approach would produce charges for service far in excess of firm rates.

While the parties concurred in the need for an I-6 schedule, there was substantial disagreement on whether the I-3 and I-5 schedules should in turn be closed to new customers. The I-3 and I-5 schedules have an existing "ever greening" provision requiring that a customer give Edison 5 years' notice in order to discontinue service under this schedule. These schedules, however, do not provide a notice period governing Edison's discontinuance of the schedules.

PSD states that it is aware customers incur some costs in adapting their facilities to interruptibility. As a compromise to accommodate the transition from I-3 and I-5 to the I-6 schedule, PSD therefore recommended in its brief that the Commission allow Edison to take new customers on the I-3 and I-5 schedules, but that these two schedules be closed after 1990 in favor of I-6 exclusively.

Edison does not believe that either I-3 or I-5 should be closed to new customers. Edison states that its present I-3 and I-5 rates are far more than just interruptible options. These two schedules, according to Edison, are the only available large power rate options which currently result in an average rate which is roughly equivalent to what rates should be if they were based on EPMC. Edison states that these rates are therefore needed reduction in the need for Edison to negotiate separate contract rates with its customers.

The need for a TOU-8-SOP rate option is clear. This option is another step toward cost-based rates which provide customers with the most accurate price signals regarding their use and an opportunity to change those usage patterns to reduce costs. Edison has indicated that it is also assisted by such a schedule as it encourages consumption and increases sales in the off-peak period thereby offsetting any minimum load "problem" which it might experience.

We have reviewed the methods by which Edison and PSD have attempted to estimate the number of customers who will migrate from the TOU-8 schedule to TOU-8-SOP and find a significant difference between these estimates. We believe that PSD's approach, which was based on several refinements of its estimate, may provide a more accurate and conservative basis for determining the estimated change. We are reluctant to require that the large customer group shoulder a significant revenue deficiency without a greater degree of assurance that this level of migration will result. We therefore adopt as reasonable PSD's proposed TOU-8-SOP time periods, rate structure, and rates.

c. <u>Interruptible Rates</u>

Interruptible rates have been available as options to Edison customers for some time. These schedules allow a customer who has less need for guaranteed service reliability to receive a lower rate in exchange for interruptions in his service. These lower rates appear as discounts provided under the interruptible schedules.

Edison has several existing interruptible schedules, I-1 through I-5. These schedules vary with the size of qualifying customer, the required degree of notice for interruption, and other factors. In this proceeding, Edison originally proposed that its interruptible schedules should remain unchanged with the exception until a full EPMC revenue allocation is achieved to permit Edison to compete with uneconomic alternatives.

Edison also states that the proposed I-5 rate was specifically designed to meet the intent of Section 743 of the Public Utilities Code requiring Edison to provide sufficient incentives to steel and food producers. Edison states that PSD did not consider this intent in its proposal and therefore did not develop a rate for that schedule designed to permit Edison to compete with rates available in other states.

If PSD's current recommendation to keep Schedules I-3 and I-5 open through 1990 were adopted, Edison believes that there would be no need to decide the issue of the status of these schedules in this proceeding. Edison states that since its next general rate case will be undertaken in 1990, the disposition of the I-3 and I-5 schedules is best left to that proceeding.

CLECA/CSPG similarly advocate the retention of Edison's I-3 and I-5 schedules. According to CLECA/CSPG, being on interruptible rates with the present level of incentives is the only way its industry members can achieve low enough rates to economically compete in their difficult markets.

CLECA/CSPG assert that I-3 and I-5 should be kept open in recognition of the long-term commitments which the interruptible customers have made to the utility and the substantial investment of these customers in protective and load-shedding equipment needed for safe and timely interruptions. CLECA/CSPG state that one of the benefits of the I-3 and I-5 schedules is to bring large customers closer to the Commission's stated long-term goal of cost-based rates. The absence of these schedules will, according to CLECA/CSPG, require these customers to shift to the I-6 schedule. CLECA/CSPG assert that the rate increase to these customers caused by this change only increases the incentives for these customers to bypass the utility system, negotiate contract rates with the utility, or reduce or terminate of eliminating Schedule I-4, a recommendation to which PSD agreed due to the lack of use of this schedule by interruptible customers. In its testimony, however, PSD proposed the closing of Schedules I-2, I-3, and I-5 to new customers and the establishment of a new schedule, I-6. Schedule I-1 is already closed to new customers. PSD also proposed two new interruptible Schedules TOU-8-SOP-1A and TOU-8-SOP-1B, which combine features of TOU-8-SOP and I-6.

(1). Parties Positions

PSD asserts that the interruptible discounts should be based on the value of the system capacity at the time of interruption. PSD states that the present interruptible schedules are not cost-based. PSD therefore proposes that the I-2, I-3, and I-5 schedules be closed and that the new schedule I-6 be established.

The newly proposed schedule, I-6, is described by PSD as being similar to TOU-8, but with four time periods instead of three. The four would include three regular time periods like those included in TOU-8 and reflect the applicable unbundled components of system savings, i.e., energy and demand. PSD states that demand charges in these periods would be adjusted by the same ERI used to adjust QF capacity payments in order to reflect the value of the demand reduced by these interruptible customers.

PSD states that the fourth time period which it established in Schedule I-6 represents the 40 hours in the summer which are most likely to experience a call for interruption based on loss of load probabilities (LOLP). PSD states that a failure to interrupt when requested during those periods would lead to a penalty rate being imposed. PSD has based this penalty on the value of the service at the time of the interruption request. Under the I-6 schedule, PSD has also provided that customers could, as with I-3 and I-5, choose to designate a level of firm demand not subject to interruption. PSD states that its proposed I-6 schedule would allow a customer to select either immediate interruptibility operations in Edison's service area. CLECA/CSPG also note that rates under the I-3 and I-5 schedules are still above short-run marginal costs.

If Schedules I-3 and I-5 are to be closed as suggested by PSD, CLECA/CSPG ask that these schedules remain open indefinitely for customers who are currently on those schedules. Based on the five-year notice provision to leave the schedule, CLECA/CSPG ask that the schedules be closed to new customers no sooner than January 1, 1993, and that customers be given the opportunity to shift, if they wish, to another interruptible schedule at that time. CLECA/CSPG also recommend that if the Commission adopts the proposed I-6 schedules, those customers on the I-3 and I-5 schedules be given the opportunity to convert to I-6 at any time, due to its cost-based nature.

IU states that fairness and other sound policy considerations dictate that Edison's existing interruptible Schedules I-3 and I-5 remain open and that contracts already concluded under those schedules be honored. IU notes, as CLECA/CSPG did, that interruptible rates involve a long-term commitment by customers. According to IU, PSD's proposed elimination of these schedules ignores the fact that these customers entered contracts in good faith reliance and with a reasonable expectation of continued rate benefits justifying capital investments necessary to becoming an interruptible customer. IU also notes that in terms of avoiding bypass, many of the customers that are currently purchasing interruptible service from Edison would choose to leave the system absent the present discounts.

IU also objects to PSD's present recommendation to retain the I-3 and I-5 schedules through 1990. In IU's view, the negative impacts of even this change would be similar to those which interruptible customers would experience with an immediate elimination of I-3 and I-5.

or 1-hour notice. I-6 would be available to standby customers, including cogenerators for whom current Schedules I-3 or I-5 are not available.

During hearings in this proceeding, Edison also endorsed the concept of an I-6 schedule. Edison, however, differed with PSD with respect to assumptions relating to the period of time during which the value of future capacity is to be discounted, the basis on which capacity is to be valued, and the choice of ERI to be applied to that discount. Edison states that the ERI assumption is critical since interruptible rates are highly sensitive to that assumption.

With respect to Edison's assumptions, PSD particularly objects to Edison having based the value of capacity on the marginal cost of generation only. In contrast, PSD states that it has based this value on the marginal costs of generation, transmission, and distribution.

Interested parties to this proceeding generally supported the establishment of an I-6 schedule. Among these parties, CLECA/ CSPG believes that PSD's proposed I-6 is a viable new interruptible rate option whose design is more directly tied to the overall large power rate design than is the current interruptible rate design. Edison's proposed I-6 schedule is flawed, in CLECA/CSPG's view, for its failure to consider the value of saved transmission and distribution capacity valuing interruptibility to utilities.

CMA believes, however, that interruptible rates should be based on the cost of serving the interruptible customer and not the value of curtailability in an excess capacity situation. For a cost-based interruptible rate, CMA states that the existence or non-existence of excess generation capacity is irrelevant and that those rates must ultimately reflect a cost, and not a value, analysis. Because such a cost analysis was not

CMA recommends the closing of Schedules I-3 and I-5 as long as the contracts of existing customers continue to evergreen. According to CMA, the need to recognize stability in rates and equity for customers who have made changes in their operations to accommodate interruptible service requires the continuance of these contracts.

(2) Discussion

In D.86-12-091, among the criteria which we applied to the design of interruptible rate options for PG&E was the continuation of the requirement of a customer commitment to a three-year contract and the imposition of penalties for failure to curtail or interrupt. With respect to the three-year contract commitment, we found it reasonable for existing customers to expect some consistency in design criteria for the life of this contract. We therefore determined that existing incentives should be maintained for the remaining life of all contracts signed prior to the effective date of D.86-12-091. For new contracts and contract extensions signed after the effective date of that order, we based the interruptible incentives on full marginal cost without adjustment. (D.86-12-091, at p. 66.)

To ensure that customers on these rate options participated in the program by interrupting or curtailing service, we also determined that a penalty should be imposed for nonconformance. For each time a customer failed to interrupt after notification for PG&E, we found that the customer should be required to pay 1.1 times the incentive received in that month for the load not interrupted or curtailed. Customers would therefore be allowed to fail to comply with approximately 11 such requests before the penalties assessed would equal the annual interruptible discount. (D.86-12-091, at pp. 66-67.)

By Resolution E-3044 issued August 26, 1987, we altered these penalty provisions by authorizing PG&E to amend that penalty to provide that only three instances of noncompliance would presented in this proceeding, CMA asks the Commission to consider such cost issues in the future.

CMA also asserts that while penalties should exist for failures to curtail or interrupt, those penalties should be reasonable. In CMA's opinion, the existing graduated penalty provisions of Schedule I-5, adjusted to the amount of interruptible discount provided in the I-6 schedule, should be fully adequate. The concept of an escalating penalty is, in CMA's view, far more reasonable than PSD's and Edison's proposal to eliminate the discount ($33/kw/year for Edison and $80.80/kW/year for PSD) for a single failure to curtail. CMA also argues that subsequent failures using this approach would produce charges for service far in excess of firm rates.

While the parties concurred in the need for an I-6 schedule, there was substantial disagreement on whether the I-3 and I-5 schedules should in turn be closed to new customers. The I-3 and I-5 schedules have an existing "ever greening" provision requiring that a customer give Edison 5 years' notice in order to discontinue service under this schedule. These schedules, however, do not provide a notice period governing Edison's discontinuance of the schedules.

PSD states that it is aware customers incur some costs in adapting their facilities to interruptibility. As a compromise to accommodate the transition from I-3 and I-5 to the I-6 schedule, PSD therefore recommended in its brief that the Commission allow Edison to take new customers on the I-3 and I-5 schedules, but that these two schedules be closed after 1990 in favor of I-6 exclusively.

Edison does not believe that either I-3 or I-5 should be closed to new customers. Edison states that its present I-3 and I-5 rates are far more than just interruptible options. These two schedules, according to Edison, are the only available large power rate options which currently result in an average rate cause the resulting penalties to equal the annual interruptible discount. This penalty approach was based on a set of graduated excess demand charges. Therefore, for the first failure to interrupt or curtail within twelve months the charge would be one-sixth of the annual incentive per kilowatt. For the second non-performance, the incremental charge would increase to one-third of the annual incentive with total charges assessed equaling one-half of that incentive. For the third and any subsequent non-performance, the incremental charge would be one-half of the annual incentive.

In authorizing this amendment to PG&E's interruptible penalty, we relied on the analysis of our Evaluation and Compliance (E&C) Division that this change would increase customer incentives to reduce load when requested. The change was found to also provide the utility with a high degree of reliability from these customers for load relief during emergency situations.

In this proceeding, issues similar to those raised with respect to PG&E's interruptible rate design have been presented. Specifically, we have before us the proposal by PSD to commence a new interruptible schedule based on marginal costs (I-6) and to close two previous schedules (I-3 and I-5) which are to be superseded by the new schedule. We find that PSD's proposed I-6 schedule, to which the majority of the parties have agreed in concept, achieves the goal of providing cost-based rates and in turn accurate price signals to interruptible customers. Certain modifications of this proposal, however, are required.

Specifically, we find the penalty for failure to interrupt as proposed by either PSD or Edison is too harsh and would act as a significant deterrent to customers moving to this schedule. As CMA has pointed out, the levels of the penalties recommended by these parties would essentially eliminate the discount upon a single failure to curtail with subsequent failures producing charges far in excess of firm rates.

which is roughly equivalent to what rates should be if they were based on EPMC. Edison states that these rates are therefore needed until a full EPMC revenue allocation is achieved to permit Edison to compete with uneconomic alternatives.

Edison also states that the proposed I-5 rate was specifically designed to meet the intent of Section 743 of the Public Utilities Code requiring Edison to provide sufficient incentives to steel and food producers. Edison states that PSD did not consider this intent in its proposal and therefore did not develop a rate for that schedule designed to permit Edison to compete with rates available in other states.

If PSD's current recommendation to keep Schedules I-3 and I-5 open through 1990 were adopted, Edison believes that there would be no need to decide the issue of the status of these schedules in this proceeding. Edison states that since its next general rate case will be undertaken in 1990, the disposition of the I-3 and I-5 schedules is best left to that proceeding.

CLECA/CSPG similarly advocate the retention of Edison's I-3 and I-5 schedules. According to CLECA/CSPG, being on interruptible rates with the present level of incentives is the only way its industry members can achieve low enough rates to economically compete in their difficult markets.

CLECA/CSPG assert that I-3 and I-5 should be kept open in recognition of the long-term commitments which the interruptible customers have made to the utility and the substantial investment of these customers in protective and load-shedding equipment needed for safe and timely interruptions. CLECA/CSPG state that one of the benefits of the I-3 and I-5 schedules is to bring large customers closer to the Commission's stated long-term goal of cost-based rates. The absence of these schedules will, according to CLECA/CSPG, require these customers to shift to the I-6 schedule. CLECA/CSPG assert that the rate increase to these customers caused by this change only increases

While we find PSD's and Edison's proposals unduly harsh, Resolution E-3044 reflects that the opposite extreme of up to 11 failures to curtail or interrupt in a 12-month period is a too lenient penalty. As that resolution indicates, the result of such an approach is to reduce the customer's incentive to reduce load when requested. Since the goal of this schedule is to provide lower rates for less reliable service, we believe that reasonable penalties ensuring that the customer respond to requests to interrupt are essential. We find that the graduated approach for such penalties, adopted in Resolution E-3044, provides for such penalties.

We therefore find reasonable the inclusion of penalties for the new I-6 schedule similar to those adopted for PG&E in Resolution E-3044. Specifically, the penalties provided under the I-6 schedule for failure to respond to an Edison request to reduce load will be based on the same set of graduated excess demand charges adopted for PG&E in Resolution E-3044.

In this proceeding, we have again also been faced with existing interruptible schedules which require a specified contract term commitment and a new schedule which is based on marginal costs. As we concluded in D.86-12-091, we find that it is reasonable for the interruptible customers to expect consistency in rate design for the term of their contracts signed in response to that rate design. Additionally, CLECA/CSPG, IU, and CMA have raised valid arguments for maintaining the existing schedules for customers who have made investments in reliance on the availability of those schedules.

We are also concerned with Edison's assertion that PSD may not have considered the intent of Section 743 of the California Public Utilities Code in developing it proposed I-6 rate schedule. Section 743 specifically requires a utility to provide interruptible rates to steel producers and food processors lower than the utility's system average rate. The statute, with which we the incentives for these customers to bypass the utility system, negotiate contract rates with the utility, or reduce or terminate operations in Edison's service area. CLECA/CSPG also note that rates under the I-3 and I-5 schedules are still above short-run marginal costs.

If Schedules I-3 and I-5 are to be closed as suggested by PSD, CLECA/CSPG ask that these schedules remain open indefinitely for customers who are currently on those schedules. Based on the five-year notice provision to leave the schedule, CLECA/CSPG ask that the schedules be closed to new customers no sooner than January 1, 1993, and that customers be given the opportunity to shift, if they wish, to another interruptible schedule at that time. CLECA/CSPG also recommend that if the Commission adopts the proposed I-6 schedules, those customers on the I-3 and I-5 schedules be given the opportunity to convert to I-6 at any time, due to its cost-based nature.

IU states that fairness and other sound policy considerations dictate that Edison's existing interruptible Schedules I-3 and I-5 remain open and that contracts already concluded under those schedules be honored. IU notes, as CLECA/CSPG did, that interruptible rates involve a long-term commitment by customers. According to IU, PSD's proposed elimination of these schedules ignores the fact that these customers entered contracts in good faith reliance and with a reasonable expectation of continued rate benefits justifying capital investments necessary to becoming an interruptible customer. IU also notes that in terms of avoiding bypass, many of the customers that are currently purchasing interruptible service from Edison would choose to leave the system absent the present discounts.

IU also objects to PSD's present recommendation to retain the I-3 and I-5 schedules through 1990. In IU's view, the negative impacts of even this change would be similar to those are required to comply, is designed to ensure a competitive level of incentives for these customers.

While we believe that these circumstances require that the I-3 and I-5 schedules remain open for a period of time, we do not wish to prolong service under these schedules at a time when an interruptible schedule based on marginal costs has also been made available to these customers. Our goal for charges incurred for interruptible service is the same as that for all other services -- cost-based rates.

For these reasons, we find that it is reasonable to leave the I-3 and I-5 schedules open for new customers until January, 1, 1991. At that time, Edison's next general rate case will have concluded, any "imperfections" in the I-6 schedule will have been resolved in that proceeding, and customers will have received three-years notice of the intended closing of these schedules. To ensure the communication of this notice, Edison's tariffs should specifically state that the I-3 and I-5 schedules will be closed to new customers after January 1, 1991.

For existing customers, we believe that it is reasonable for those customers who had signed a contract with Edison under the I-3 and I-5 schedules prior to the effective date of this decision to complete that contract term under those schedules. Therefore, the I-3 and I-5 schedules will be closed effective January 1, 1993, to this group of existing customers. For those new customers signing contracts under the I-3 and I-5 schedules between the date of this decision and January 1, 1991, the terms of their contracts should provide for their termination with respect to Schedules I-3 and I-5 no later than January 1, 1993, with the remainder of any unexpired contract commitment being served under Schedule I-6 after that time. Our goal in adopting this approach is to ensure that Edison can rely on the five-year interruptible commitment whether that commitment relates to which interruptible customers would experience with an immediate elimination of I-3 and I-5.

CMA recommends the closing of Schedules I-3 and I-5 as long as the contracts of existing customers continue to evergreen. According to CMA, the need to recognize stability in rates and equity for customers who have made changes in their operations to accommodate interruptible service requires the continuance of these contracts.

(2) <u>Discussion</u>

In D.86-12-091, among the criteria which we applied to the design of interruptible rate options for PG&E was the continuation of the requirement of a customer commitment to a three-year contract and the imposition of penalties for failure to curtail or interrupt. With respect to the three-year contract commitment, we found it reasonable for existing customers to expect some consistency in design criteria for the life of this contract. We therefore determined that existing incentives should be maintained for the remaining life of all contracts signed prior to the effective date of D.86-12-091. For new contracts and contract extensions signed after the effective date of that order, we based the interruptible incentives on full marginal cost without adjustment. (D.86-12-091, at p. 66.)

To ensure that customers on these rate options participated in the program by interrupting or curtailing service, we also determined that a penalty should be imposed for nonconformance. For each time a customer failed to interrupt after notification for PG&E, we found that the customer should be required to pay 1.1 times the incentive received in that month for the load not interrupted or curtailed. Customers would therefore be allowed to fail to comply with approximately 11 such requests before the penalties assessed would equal the annual interruptible discount. (D.86-12-091, at pp. 66-67.)

Schedule I-3, I-5, or I-6. As recommended by PSD and Edison, Schedule I-4 should be closed effective with this decision.

Finally, we address CLECA/CSPG's suggestion that current I-3 and I-5 customers be entitled to switch to the I-6 schedule at any time due to the cost-based nature of that schedule. The assurance provided by a contract commitment under the interruptible schedules is that Edison can estimate into the future the level of energy which will be available for Edison to respond to emergency situations. The specific schedule under which this commitment is made should not alter Edison's ability to rely on that load being available.

We therefore find reasonable CLECA/CSPG's recommendation which will also promote the use of the cost-based interruptible schedule, I-6. We will therefore direct Edison to include in its tariffs a provision permitting I-3 and I-5 customers to switch to the I-6 schedule at any time conditioned on the remaining term of its I-3 and I-5 contracts being completed under the I-6 schedule. The customer's change to the I-6 schedule should not result in the customer being billed the difference between the I-6 and I-3 or I-5 rates based on receipt of service under those schedules for part of the overall contract term.

With respect to the interruptible rates provided under Schedule I-6, we find that PSD's approach most accurately bases those rates on the value of interruptibility to Edison. It is necessary to adjust these rates, however, to reflect our adopted ERI value for Edison of 0.43. With this change in assumption, we otherwise find reasonable PSD's proposed methodology for calculating these rates.

As we have noted CMA suggests that our adopted approach of basing interruptible rates on the value of such interruption to the utility fails to reflect the cost of serving the interruptible customer. CMA has acknowledged, however, that this issue was not sufficiently addressed in this proceeding to

By Resolution E-3044 issued August 26, 1987, we altered these penalty provisions by authorizing PG&E to amend that penalty to provide that only three instances of noncompliance would cause the resulting penalties to equal the annual interruptible discount. This penalty approach was based on a set of graduated excess demand charges. Therefore, for the first failure to interrupt or curtail within twelve months the charge would be one-sixth of the annual incentive per kilowatt. For the second non-performance, the incremental charge would increase to one-third of the annual incentive with total charges assessed equaling one-half of that incentive. For the third and any subsequent non-performance, the incremental charge would be one-half of the annual incentive.

In authorizing this amendment to PG&E's interruptible penalty, we relied on the analysis of our Evaluation and Compliance (E&C) Division that this change would increase customer incentives to reduce load when requested. The change was found to also provide the utility with a high degree of reliability from these customers for load relief during emergency situations.

In this proceeding, issues similar to those raised with respect to PG&E's interruptible rate design have been presented. Specifically, we have before us the proposal by PSD to commence a new interruptible schedule based on marginal costs (I-6) and to close two previous schedules (I-3 and I-5) which are to be superseded by the new schedule. We find that PSD's proposed I-6 schedule, to which the majority of the parties have agreed in concept, achieves the goal of providing cost-based rates and in turn accurate price signals to interruptible customers. Certain modifications of this proposal, however, are required.

Specifically, we find the penalty for failure to interrupt as proposed by either PSD or Edison is too harsh and would act as a significant deterrent to customers moving to this schedule. As CMA has pointed out, the levels of the penalties warrant a change in our approach. For Edison's next general rate case, however, we will direct Edison and PSD to develop an interruptible schedule based on cost of service to the interruptible customer, in addition to a schedule based on the current consideration of the value of interruptiblity to the utility. In this way, we will not only have the schedules to compare, but also the insights of the parties as to the merits of changing our approach for determining interruptible incentives to a cost of service basis.

d. Contract Rates

As we have stated previously, the Commission has concluded that special contracts or contract rates can serve as a means of mitigating uneconomic bypass. In this proceeding, Edison has proposed two contract rate options: the Incremental Sales Rate and the Self-Generation Deferral Rate. Edison believes that these options will enable it (1) to reduce its rates to levels which are closer to its marginal cost of providing service, in order to retain the loads of credible bypass candidates; (2) to provide cost-based price signals to promote new sales from customers with growing loads; and (3) to promote economic efficiency by permitting Edison to make better use of its existing generating capacity.

According to Edison, the Incremental Sales Rate, proposed schedule TOU-8-CR-1, consists of a high fixed charge and reduced demand and energy charges with the initial term of 5 years. The fixed payment would be based on a portion of the contribution to margin the customer would have made had they remained on the regular applicable rate.

Under the Self-Generation Deferral Rate, proposed schedule TOU-8-CR-2, a customer with self-generation potential would be charged the same costs which the customer would incur by self-generating. For those with an economic option to leave the system, Edison proposes to charge these customers the cost which the customer would incur acquiring the capacity and energy from recommended by these parties would essentially eliminate the discount upon a single failure to curtail with subsequent failures producing charges far in excess of firm rates.

While we find PSD's and Edison's proposals unduly harsh, Resolution E-3044 reflects that the opposite extreme of up to 11 failures to curtail or interrupt in a 12-month period is a too lenient penalty. As that resolution indicates, the result of such an approach is to reduce the customer's incentive to reduce load when requested. Since the goal of this schedule is to provide lower rates for less reliable service, we believe that reasonable penalties ensuring that the customer respond to requests to interrupt are essential. We find that the graduated approach for such penalties, adopted in Resolution E-3044, provides for such penalties.

We therefore find reasonable the inclusion of penalties for the new I-6 schedule similar to those adopted for PG&E in Resolution E-3044. Specifically, the penalties provided under the I-6 schedule for failure to respond to an Edison request to reduce load will be based on the same set of graduated excess demand charges adopted for PG&E in Resolution E-3044.

In this proceeding, we have again also been faced with existing interruptible schedules which require a specified contract term commitment and a new schedule which is based on marginal costs. As we concluded in D.86-12-091, we find that it is reasonable for the interruptible customers to expect consistency in rate design for the term of their contracts signed in response to that rate design. Additionally, CLECA/CSPG, IU, and CMA have raised valid arguments for maintaining the existing schedules for customers who have made investments in reliance on the availability of those schedules.

We are also concerned with Edison's assertion that PSD may not have considered the intent of Section 743 of the California Public Utilities Code in developing it proposed I-6 rate another source. For the remaining customers, Edison would charge its costs of producing electricity in terms of total revenue requirement.

Edison believes that the Commission should adopt the Incremental Sales Rate in this proceeding and endorse the Self-Generation Deferral Contract Rate in concept for Edison's use beginning in 1988. Edison states, however, that implementation considerations for TOU-8-CR-2 should be deferred to the 3-Rs Rulemaking (R.86-10-001) in which contract guidelines are being considered.

PSD agrees with most aspects of Edison's proposal. PSD therefore urges the Commission's adoption of the Incremental Sales Rate in this proceeding with implementation considerations for the Self-Generation Deferral Rate deferred to R.86-10-001.

CMA states that consideration of both of Edison's special contract tariff proposals should be deferred and studied as part of the policy matters being considered by the Commission in the 3-Rs Rulemaking, R.86-10-001. CMA points out that D.87-05-071 in that matter contemplates special contracts for large light and power customers under guidelines to be developed by the Commission in that proceeding. CMA believes that the Commission's actions on this subject should be consistent for all utilities.

We concur with CMA. We have made clear in D.87-05-071 that the guidelines and terms of special contracts and contract rates are to be examined and adopted in R.86-10-001. This effort will not only achieve consistency between utilities, but will also provide a single forum in which the appropriate responses to uneconomic bypass can be coordinated. In R.86-10-001, we will also be presented with the tools required to most efficiently achieve our goal of addressing uneconomic bypass. These tools will include contract guidelines proposed by all utilities and new forecasts of sales and revenue for the large power customer group which take into account regulatory revisions adopted in D.87-05-071.

schedule. Section 743 specifically requires a utility to provide interruptible rates to steel producers and food processors lower than the utility's system average rate. The statute, with which we are required to comply, is designed to ensure a competitive level of incentives for these customers.

While we believe that these circumstances require that the I-3 and I-5 schedules remain open for a period of time, we do not wish to prolong service under these schedules at a time when an interruptible schedule based on marginal costs has also been made available to these customers. Our goal for charges incurred for interruptible service is the same as that for all other services -- cost-based rates.

For these reasons, we find that it is reasonable to leave the I-3 and I-5 schedules open for new customers until January, 1, 1991. At that time, Edison's next general rate case will have concluded, any "imperfections" in the I-6 schedule will have been resolved in that proceeding, and customers will have received three-years notice of the intended closing of these schedules. To ensure the communication of this notice, Edison's tariffs should specifically state that the I-3 and I-5 schedules will be closed to new customers after January 1, 1991.

For existing customers, we believe that it is reasonable for those customers who had signed a contract with Edison under the I-3 and I-5 schedules prior to the effective date of this decision to complete that contract term under those schedules. Therefore, the I-3 and I-5 schedules will be closed effective January 1, 1993, to this group of existing customers. For those new customers signing contracts under the I-3 and I-5 schedules between the date of this decision and January 1, 1991, the terms of their contracts should provide for their termination with respect to Schedules I-3 and I-5 no later than January 1, 1993, with the remainder of any unexpired contract commitment being served under Schedule I-6 after that time. Our goal in adopting

As we have discussed in the Revenue Allocation portion of this order, the implementation of contract rate schedules requires more than the adoption of specific tariff terms. We must also be able to determine the level of revenue deficiency resulting from implementation of these schedules, and the manner in which that deficiency is to be allocated to customers. All of these concerns are best addressed in R.86-10-001 to ensure uniform and appropriate standards.

We therefore find that Edison's proposed contract schedules, TOU-CR-1 and TOU-CR-2, should not be adopted in this proceeding. These proposals, however, do appear to be responsive to the bypass issue and would properly be presented in the context of R.86-10-001.

e. Standby Charges

In response to the needs of customers who have chosen to provide their own generation, Edison offers backup or "standby" service. This service is provided when the customer, for whom the installation of its own backup facilities would not be economic, requires utility service due to an outage at its generation facility.

In this proceeding, PSD has proposed a standby schedule to which Edison has agreed. The effect of this proposal would be to close current Edison Schedules SCG-1 through 3 and establish new Schedule S which would be available to standby customers along with new Schedule I-6. Edison does not agree, however, with PSD's additional suggestion to impose a "rate limiter" on standby charges. This proposal, as well as all other suggested "rate limiters," are discussed in a separate section below.

(1) Parties Positions

Under PSD's proposal, standby customers would contract for a certain level of standby service on any non-standby schedule. The customer would pay the applicable customer charge for that service schedule every month and the maximum demand this approach is to ensure that Edison can rely on the five-year interruptible commitment whether that commitment relates to Schedule I-3, I-5, or I-6. As recommended by PSD and Edison, Schedule I-2 should be closed and Schedule I-4 should be eliminated effective with this decision.

Finally, we address CLECA/CSPG's suggestion that current I-3 and I-5 customers be entitled to switch to the I-6 schedule at any time due to the cost-based nature of that schedule. The assurance provided by a contract commitment under the interruptible schedules is that Edison can estimate into the future the level of energy which will be available for Edison to respond to emergency situations. The specific schedule under which this commitment is made should not alter Edison's ability to rely on that load being available.

We therefore find reasonable CLECA/CSPG's recommendation which will also promote the use of the cost-based interruptible schedule, I-6. We will therefore direct Edison to include in its tariffs a provision permitting I-3 and I-5 customers to switch to the I-6 schedule at any time conditioned on the remaining term of its I-3 and I-5 contracts being completed under the I-6 schedule. The customer's change to the I-6 schedule should not result in the customer being billed the difference between the I-6 and I-3 or I-5 rates based on receipt of service under those schedules for part of the overall contract term.

Credits and penalties provided under Schedules I-1, I-2, I-3, and I-5 are not changed on an annual basis, but are recalculated to reflect a reduced number of on-peak hours resulting from the elimination of the on-peak period in the winter months. For Schedule I-5, however, the off-peak credit of $0.025/kWh applied to the off-peak floor rate of $0.05/kWh results in a $0.025/kWh rate, a rate which is less than the marginal energy cost. Rather than adopting a charge below the marginal energy cost, we will direct Edison to take the difference between the charges for that schedule for the demand specified in their contract. If the standby customer takes service under the non-standby schedule, the maximum demand charge on the service taken would be waived up to the contract level.

In support of its proposal, PSD states that standby customers, like all other customers, should pay for services based on the costs Edison incurs in providing those services. In PSD's opinion, the costs for which standby customers should be responsible should therefore include those costs which they impose on the system even when no active demands are placed on the utility system. PSD states that such services include a meter, service drop, billing, and local distribution facilities sized to the maximum demand potential of the standby customer. With respect to this latter cost, PSD and Edison concur with the use of the full noncoincident demand costs, reflecting both marginal distribution costs and a portion of marginal transmission costs.

Edison has agreed with both PSD's proposed standby charges and terms as well as the principles supporting that proposal. PSD's approach, according to Edison, is required to ensure Edison of full recovery of distribution-related costs from customers with self-generation. Edison states that for a customer with both standby and supplemental loads, the combination of the standby and non-time related demand charges is intended to compensate Edison for its costs of serving both types of loads.

In the future, Edison also believes that a generation and transmission component may be appropriate to include in the determination of the standby charge in addition to the distribution component. Edison states that some consideration should also be given in the future to the equity of allowing a standby customer to be charged for replacement and backup service at average rates.

With respect to the interested parties, CMA, DGS, and the CSC all agree that standby rates should be cost-based.

marginal energy cost and the off-peak rate and reduce the customer's bill by an amount equal to that difference.

With respect to the interruptible rates provided under Schedule I-6, we find that PSD's approach most accurately bases those rates on the value of interruptibility to Edison. It is necessary to adjust these rates, however, to reflect our adopted ERI value for Edison of 0.43. With this change in assumption, we otherwise find reasonable PSD's proposed methodology for calculating these rates. We also adopt the two super off-peak interruptible rate options to which Edison and PSD have agreed (TOU-8-SOP-1A and TOU-8-SOP-1B).

As we have noted CMA suggests that our adopted approach of basing interruptible rates on the value of such interruption to the utility fails to reflect the cost of serving the interruptible customer. CMA has acknowledged, however, that this issue was not sufficiently addressed in this proceeding to warrant a change in our approach. For Edison's next general rate case, however, we will direct Edison and PSD to develop an interruptible schedule based on cost of service to the interruptible customer, in addition to a schedule based on the current consideration of the value of interruptiblity to the utility. In this way, we will not only have the schedules to compare, but also the insights of the parties as to the merits of changing our approach for determining interruptible incentives to a cost of service basis.

d. Contract Rates

As we have stated previously, the Commission has concluded that special contracts or contract rates can serve as a means of mitigating uneconomic bypass. In this proceeding, Edison has proposed two contract rate options: the Incremental Sales Rate and the Self-Generation Deferral Rate. Edison believes that these options will enable it (1) to reduce its rates to levels which are closer to its marginal cost of providing service, in order to

However, each has urged the Commission to consider means of mitigating rate shock in order to avoid discouraging customers from taking this service.

CMA therefore concurs with PSD's approach to calculating these rates and requiring a rate limiter. CMA also proposes that the same transitional phase-in be adopted for standby charges as has been proposed for domestic customers with respect to the move to a full EPMC revenue allocation.

To ensure that standby charges reflect the true costs imposed on the utility system by standby customers, DGS recommends that standby customers be charged for energy and demand when it is taken and that standby tariffs reflect the special characteristics of this service. Specifically, DGS supports the suggestions made by CMA during hearings in this proceeding (1) to permit all standby customers to select their own level of contract demand for standby service; (2) to phase-in standby rates; (3) to avoid imposing both a standby charge and a ratcheted maximum demand charge on standby customers; and (4) to reduce on-peak and mid-peak charges for regular service to standby customers in recognition of their lower coincidence demand. By adopting these recommendations, DGS asserts that the standby customer will be able to more effectively manage his own loads in response to accurate price signals.

The CSC generally supports PSD's proposed standby charge as modified by PSD's proposed rate limiter. The CSC disagrees, however, with Edison's and PSD's proposal to apply the standby charge against the standby load of all customers. The CSC asserts that customers that have paid for all facilities necessary for interconnection with Edison's transmission system must be exempt from the standby charge. According to the CSC, the goal of cost-based rates would not be achieved for standby customers if that customer's rates include equipment and construction costs associated with distribution or transmission facilities for which retain the loads of credible bypass candidates; (2) to provide cost-based price signals to promote new sales from customers with growing loads; and (3) to promote economic efficiency by permitting Edison to make better use of its existing generating capacity.

According to Edison, the Incremental Sales Rate, proposed schedule TOU-8-CR-1, consists of a high fixed charge and reduced demand and energy charges with the initial term of 5 years. The fixed payment would be based on a portion of the contribution to margin the customer would have made had they remained on the regular applicable rate.

Under the Self-Generation Deferral Rate, proposed schedule TOU-8-CR-2, a customer with self-generation potential would be charged the same costs which the customer would incur by self-generating. For those with an economic option to leave the system, Edison proposes to charge these customers the cost which the customer would incur acquiring the capacity and energy from another source. For the remaining customers, Edison would charge its costs of producing electricity in terms of total revenue requirement.

Edison believes that the Commission should adopt the Incremental Sales Rate in this proceeding and endorse the Self-Generation Deferral Contract Rate in concept for Edison's use beginning in 1988. Edison states, however, that implementation considerations for TOU-8-CR-2 should be deferred to the 3-Rs Rulemaking (R.86-10-001) in which contract guidelines are being considered.

PSD agrees with most aspects of Edison's proposal. PSD therefore urges the Commission's adoption of the Incremental Sales Rate in this proceeding with implementation considerations for the Self-Generation Deferral Rate deferred to R.86-10-001.

CMA states that consideration of both of Edison's special contract tariff proposals should be deferred and studied as part of the policy matters being considered by the Commission in the 3-Rs the customer has paid. Therefore, the CSC urges the waiver of the costs of these facilities in standby rates if they have been paid by the self-generating customer.

In its briefs, Edison responded to the recommendations of each of the interested parties. Specifically, Edison disagrees with the suggestion of CMA and DGS that standby charges should be phased-in in the same manner as the EPMC revenue allocation. Edison states that the impact of the increase proposed by Edison and PSD for standby charges on the total energy costs of the standby customer should be small. Even if the impact were greater, Edison states that there is no connection in this rate case between the substantial rate impacts for domestic customers which would result from the immediate move to EPMC revenue allocation and rate impacts for standby customers.

Edison also disagrees with CMA's and DGS's proposal that standby customers be allowed to select their own level of standby demand. According to Edison, this customer determination of standby demand would alter the current and better practice of this level being decided by Edison and the standby customer working together. Edison states that once this level has been determined and facilities have been installed, a commitment is made by both parties. To permit a customer to "back down" their standby demand level, according to Edison would be detrimental to other customers to whom the cost recovery of the "excess facilities" would be shifted, but who would receive no benefit from those facilities.

Edison also asserts that DGS's claim that Edison will collect excessive revenue from standby customers by levying both the ratcheted maximum demand charge and the standby charge is no longer valid. Specifically, Edison states that it has agreed with PSD to charge standby charges higher than it had originally proposed, but provide an exemption from the non-time related demand charges for the standby portion of a standby customer's load.

Rulemaking, R.86-10-001. CMA points out that D.87-05-071 in that matter contemplates special contracts for large light and power customers under guidelines to be developed by the Commission in that proceeding. CMA believes that the Commission's actions on this subject should be consistent for all utilities.

We concur with CMA. We have made clear in D.87-05-071 that the guidelines and terms of special contracts and contract rates are to be examined and adopted in R.86-10-001. This effort will not only achieve consistency between utilities, but will also provide a single forum in which the appropriate responses to uneconomic bypass can be coordinated. In R.86-10-001, we will also be presented with the tools required to most efficiently achieve our goal of addressing uneconomic bypass. These tools will include contract guidelines proposed by all utilities and new forecasts of sales and revenue for the large power customer group which take into account regulatory revisions adopted in D.87-05-071.

As we have discussed in the Revenue Allocation portion of this order, the implementation of contract rate schedules requires more than the adoption of specific tariff terms. We must also be able to determine the level of revenue deficiency resulting from implementation of these schedules, and the manner in which that deficiency is to be allocated to customers. All of these concerns are best addressed in R.86-10-001 to ensure uniform and appropriate standards.

We therefore find that Edison's proposed generic special contract schedule, TOU-CR-2, should not be adopted in this proceeding. This proposal, however, does appear to be responsive to the bypass issue and would properly be presented in the context of R.86-10-001. We find, however, that it is appropriate to consider the design of Edison's proposed rate option, TOU-8-CR-1 in this rate case, but we will defer consideration of its revenue allocation effect to R.86-10-001. Therefore, we will authorize the TOU-8-CR-1 rate as part of Edison's tariff structure and direct

Edison states, contrary to the positions of CMA and DGS, that full on- and mid-peak demand charges should apply to standby customers. According to Edison, the charges which have been proposed properly focus on the total (standby plus supplemental) load which can be metered and billed. Therefore, Edison asserts that it is appropriate to view the loads of these customers collectively, even though if viewed separately these loads could appear to be random with little coincidence with system peak loads. Edison states that when viewed collectively the loads of the standby customers exhibit many of the characteristics of the TOU-8 customer group and require their being charged at the same rate level.

Edison also rejects DGS's suggestion that standby customers be charged for energy and demand when it is taken. According to Edison, noncoincident demand-related costs are a function of the level of facilities installed and do not fluctuate with the actual level of use by the customer. These costs should therefore be recovered through a standby charge applied to a fixed level of standby demand which reflects the level of facilities installed to serve the customer's standby load.

Finally, Edison states that it disagrees with the CSC's proposal that customers who have paid for all facilities necessary for interconnection with Edison's transmission system must be exempt from the standby charge. Edison believes that the extremely low standby charge is required to compensate Edison for interconnection costs still incurred by Edison, i.e., the costs of interconnecting these customers into the utility grid.

(2) Discussion

In D.86-12-091 we concluded for PG&E that charging standby customers the same rates as other customers was not discriminatory and would result in cost-based rates. We found that taken as a group, these customers had very little energy usage relative to the demand which they placed on the system. When these that it be covered by ERAM until such time as a decision in R.86-10-001 separates Edison's customers into an ERAM and a non-ERAM group.

e. Standby Charges

In response to the needs of customers who have chosen to provide their own generation, Edison offers backup or "standby" service. This service is provided when the customer, for whom the installation of its own backup facilities would not be economic, requires utility service due to an outage at its generation facility.

In this proceeding, PSD has proposed a standby schedule to which Edison has agreed. The effect of this proposal would be to close current Edison Schedules SCG-1 through 3 and establish new Schedule S which would be available to standby customers along with new Schedule I-6. Edison does not agree, however, with PSD's additional suggestion to impose a "rate limiter" on standby charges. This proposal, as well as all other suggested "rate limiters," are discussed in a separate section below.

(1) Parties Positions

Under PSD's proposal, standby customers would contract for a certain level of standby service on any non-standby schedule. The customer would pay the applicable customer charge for that service schedule every month and the maximum demand charges for that schedule for the demand specified in their contract. If the standby customer takes service under the non-standby schedule, the maximum demand charge on the service taken would be waived up to the contract level.

In support of its proposal, PSD states that standby customers, like all other customers, should pay for services based on the costs Edison incurs in providing those services. In PSD's opinion, the costs for which standby customers should be responsible should therefore include those costs which they impose on the system even when no active demands are placed on the utility customers did take service, however, they imposed costs in the same manner as other large power customers with similar load characteristics. We found that for periods when service was not taken, it was appropriate to charge standby customers the cost of customer-related services and reserved facilities.

We find that the standby charges and terms to which PSD and Edison have agreed properly result in the uniform treatment of standby customers and other large power customers with similar load characteristics. PSD's standby proposal also effectively achieves the goal of providing cost-based rates and accurate price signals to customers who have chosen to self-generate and to those who are considering such a move. We believe that these charges properly take into consideration the load characteristics of the group as a whole and include fixed monthly charges needed to reflect the noncoincident demand of these customers.

The specificity in the cost to rate relationship sought by the interested parties appears to be aimed not so much at achieving cost-based rates as recognizing this customer group's "unique characteristics." We are certain that other TOU-8 customers can offer us instances in which their rates do not reflect their exact usage characteristics. While we have attempted to ensure rates that are cost-based and time-related, usage characteristics of the affected customer groups as a whole are an important consideration in ensuring that subsidization of the group by other customers does not result. To the extent that adverse bill impacts for these customers result from our adopted rate design, we find that PSD's rate limiter proposal for standby charges, discussed below, is a more appropriate means of adjusting these charges based on the standby customers' "unique characteristics."

In this regard, we note that the fact that a self-generator may have paid some costs associated with distribution and transmission facilities should not lead to the waiver of the system. PSD states that such services include a meter, service drop, billing, and local distribution facilities sized to the maximum demand potential of the standby customer. With respect to this latter cost, PSD and Edison concur with the use of the full noncoincident demand costs, reflecting both marginal distribution costs and a portion of marginal transmission costs.

Edison has agreed with both PSD's proposed standby charges and terms as well as the principles supporting that proposal. PSD's approach, according to Edison, is required to ensure Edison of full recovery of distribution-related costs from customers with self-generation. Edison states that for a customer with both standby and supplemental loads, the combination of the standby and non-time related demand charges is intended to compensate Edison for its costs of serving both types of loads.

In the future, Edison also believes that a generation and transmission component may be appropriate to include in the determination of the standby charge in addition to the distribution component. Edison states that some consideration should also be given in the future to the equity of allowing a standby customer to be charged for replacement and backup service at average rates.

With respect to the interested parties, CMA, DGS, and the CSC all agree that standby rates should be cost-based. However, each has urged the Commission to consider means of mitigating rate shock in order to avoid discouraging customers from taking this service.

CMA therefore concurs with PSD's approach to calculating these rates and requiring a rate limiter. CMA also proposes that the same transitional phase-in be adopted for standby charges as has been proposed for domestic customers with respect to the move to a full EPMC revenue allocation.

To ensure that standby charges reflect the true costs imposed on the utility system by standby customers, DGS standby charge which is based on <u>all</u> costs incurred by the utility to serve that customer. In the future, we suggest that Edison and PSD, however, continue to refine and clarify those costs are directly imposed on the system by the self-generator in receiving standby service. Edison, as stated previously, has in fact urged this course of action in asking that the Commission recognize the need for the inclusion of transmission and distribution components in the standby charge in the future.

Finally, we reject any request to "phase-in" standby charge increases. We fully concur with Edison that such a suggestion is appropriately reserved for such significant class rate impacts as will result to the domestic customer group from our move to an EPMC revenue allocation. As stated previously, the rate limiter proposed by PSD and discussed below is a more appropriate response to adverse bill impacts. We therefore adopt as reasonable PSD's standby rate proposal which requires the closing of Schedules SCG-1 through 3 and the establishment of Schedule S.

3. <u>Rate Limiters</u>

In this proceeding, three interested parties (FEA, CMA, and IU) have proposed that a "cap" be applied to the maximum effective change in TOU-8 customer bills to mitigate any adverse impacts caused by the adoption of cost-based rates for this customer group. PSD has also proposed a cap or "rate limiter" on its proposed standby charges. Edison opposes any cap on TOU-8 or standby rates.

a. <u>Rate Limiter Proposals</u>

FEA, CMA, and IU propose that to reduce the rate impact produced by the move toward cost-based rates a transitional "rate limiter" or maximum acceptable charge per kilowatt-hour should be adopted for the TOU-8 rate schedule. Customers whose average rate exceeds the limiter would be billed based on the limiter, rather than the filed tariff. CMA states that a phase-in of rate increases to the TOU-8 customer is required to afford that customer recommends that standby customers be charged for energy and demand when it is taken and that standby tariffs reflect the special characteristics of this service. Specifically, DGS supports the suggestions made by CMA during hearings in this proceeding (1) to permit all standby customers to select their own level of contract demand for standby service; (2) to phase-in standby rates; (3) to avoid imposing both a standby charge and a ratcheted maximum demand charge on standby customers; and (4) to reduce on-peak and mid-peak charges for regular service to standby customers in recognition of their lower coincidence demand. By adopting these recommendations, DGS asserts that the standby customer will be able to more effectively manage his own loads in response to accurate price signals.

The CSC generally supports PSD's proposed standby charge as modified by PSD's proposed rate limiter. The CSC disagrees, however, with Edison's and PSD's proposal to apply the standby charge against the standby load of all customers. The CSC asserts that customers that have paid for all facilities necessary for interconnection with Edison's transmission system must be exempt from the standby charge. According to the CSC, the goal of cost-based rates would not be achieved for standby customers if that customer's rates include equipment and construction costs associated with distribution or transmission facilities for which the customer has paid. Therefore, the CSC urges the waiver of the costs of these facilities in standby rates if they have been paid by the self-generating customer.

In its briefs, Edison responded to the recommendations of each of the interested parties. Specifically, Edison disagrees with the suggestion of CMA and DGS that standby charges should be phased-in in the same manner as the EPMC revenue allocation. Edison states that the impact of the increase proposed by Edison and PSD for standby charges on the total energy costs of the standby customer should be small. Even if the impact were the opportunity to change its load patterns, based on long-standing price signals from Edison, in response to the new price signals which will result from this proceeding. CMA claims that based on PSD's and Edison's proposals, increases of between 20% and 151.1% could result for many TOU-8 customers, with one customer receiving an increase of 267.7%.

These parties also agree that the rate limiter adopted by the Commission for PG&E's large customer group in D.86-12-091 should serve as the model for the rate limiter to be considered in this proceeding. These parties cite the Commission's conclusion in that decision that the combination of cost-based rates and a rate limiter provide customers a clear signal of future bill increases while shielding those most severely impacted from the full immediate impact of the rate change.

FEA, IU, and CMA concur that the fact that none of these parties recommended a specific level for the cap or an estimate of the revenue impact should not be a reason for rejecting a rate limiter in this proceeding. IU states that the Commission was faced with the same situation in PG&E's proceeding but was still able to impose rate limiters. FEA asserts that the absence of a recommended cap relates directly to Edison's failure to provide customer impact data as PG&E had in its proceeding. Based on the absence of the necessary information, both parties recommend that Edison be directed to work with the Commission to develop an appropriate level for the rate limiter based on the actual revenue allocated and rate structures adopted in this proceeding for TOU-8 customers. CMA states that revenue deficiencies should be reallocated to the TOU-8 class as a whole.

PSD acknowledges that an inevitable consequence of moving to marginal cost based pricing is the potential for adverse bill impacts for some customers. PSD therefore does not oppose rate limiters like those adopted for PG&E's large power customers when greater, Edison states that there is no connection in this rate case between the substantial rate impacts for domestic customers which would result from the immediate move to EPMC revenue allocation and rate impacts for standby customers.

Edison also disagrees with CMA's and DGS's proposal that standby customers be allowed to select their own level of standby demand. According to Edison, this customer determination of standby demand would alter the current and better practice of this level being decided by Edison and the standby customer working together. Edison states that once this level has been determined and facilities have been installed, a commitment is made by both parties. To permit a customer to "back down" their standby demand level, according to Edison would be detrimental to other customers to whom the cost recovery of the "excess facilities" would be shifted, but who would receive no benefit from those facilities.

Edison also asserts that DGS's claim that Edison will collect excessive revenue from standby customers by levying both the ratcheted maximum demand charge and the standby charge is no longer valid. Specifically, Edison states that it has agreed with PSD to charge standby charges higher than it had originally proposed, but provide an exemption from the non-time related demand charges for the standby portion of a standby customer's load.

Edison states, contrary to the positions of CMA and DGS, that full on- and mid-peak demand charges should apply to standby customers. According to Edison, the charges which have been proposed properly focus on the total (standby plus supplemental) load which can be metered and billed. Therefore, Edison asserts that it is appropriate to view the loads of these customers collectively, even though if viewed separately these loads could appear to be random with little coincidence with system peak loads. Edison states that when viewed collectively the loads of the standby customers exhibit many of the characteristics the rate impact is beyond a reasonable level and affects a significant number of customers.

In fact, PSD proposed such a specific rate limiter for standby charges. PSD bases its limiter on the difference in on-peak usage between firm and standby customers. According to PSD, firm customers, by taking service continually, are likely to take service during actual hours of system peak. PSD states that in contrast, there is no assurance, but only a probability, that standby customers, taking only intermittent service will take service during any hours of actual system peak. PSD notes that standby customers are also capable of selecting a time of lowest cost incurrence for scheduled maintenance.

PSD has therefore proposed an "on-peak rate limiter" for standby charges to reflect the "probability" of standby customers taking service during the "on-peak" period. PSD states that it developed the limiter, which would be applied to adjust the on-peak charges otherwise applicable to a standby customer taking service, using a complex simulation model. While PSD notes that Edison has disagreed with its proposal, PSD states that Edison's witness did in fact acknowledge that standby customers should pay their "relative share of that on-peak capacity based on the probability that they may contribute to that on-peak load." (Tr. at p. 4211.)

DGS and the CSC both support the rate limiter proposed for standby customers by PSD. These parties concur in PSD's analysis that standby service is rarely required during the system's peak and that the rate limiter would reflect the utility's lower cost of supplying standby power.

Because the proposed increased in standby charges are dramatic, DGS also believes that a rate limiter is needed to avoid extreme rate impacts which would be unfair and might encourage uneconomic bypass. DGS therefore endorses both an on-peak and mid-peak rate limiter for standby customers.

of the TOU-8 customer group and require their being charged at the same rate level.

Edison also rejects DGS's suggestion that standby customers be charged for energy and demand when it is taken. According to Edison, noncoincident demand-related costs are a function of the level of facilities installed and do not fluctuate with the actual level of use by the customer. These costs should therefore be recovered through a standby charge applied to a fixed level of standby demand which reflects the level of facilities installed to serve the customer's standby load.

Finally, Edison states that it disagrees with the CSC's proposal that customers who have paid for all facilities necessary for interconnection with Edison's transmission system must be exempt from the standby charge. Edison believes that the extremely low standby charge is required to compensate Edison for interconnection costs still incurred by Edison, i.e., the costs of interconnecting these customers into the utility grid.

(2) Discussion

In D.86-12-091 we concluded for PG&E that charging standby customers the same rates as other customers was not discriminatory and would result in cost-based rates. We found that taken as a group, these customers had very little energy usage relative to the demand which they placed on the system. When these customers did take service, however, they imposed costs in the same manner as other large power customers with similar load characteristics. We found that for periods when service was not taken, it was appropriate to charge standby customers the cost of customer-related services and reserved facilities.

We find that the standby charges and terms to which PSD and Edison have agreed properly result in the uniform treatment of standby customers and other large power customers with similar load characteristics. PSD's standby proposal also effectively achieves the goal of providing cost-based rates and accurate price

The CSC believes that PSD's rate limiter is the "best effort" to develop a fair, cost-based charge for standby service. The CSC also states that Edison's rebuttal to the rate limiter focused on irrelevant and otherwise unsupported testimony that self-generators do not operate at high annual capacity factors. According to the CSC, annual capacity factors do not reflect a self-generators' capacity factors during peak hours.

In its brief, the CSC also proposed that a separate rate limiter be considered for standby customers purchasing under the I-6 interruptible schedule. Specifically, the CSC proposes the adoption of a rate limiter developed using the same methodology as PSD applied to the standby rates, but also taking into account the 0.75 ERI associated with the I-6 schedule.

Edison rejects all of the rate limiter proposals made by PSD and the interested parties. Edison states that with respect to the proposals of IU, FEA, and CMA, none have included a specification of the cap or an estimation of the resulting revenue shortfall, the number of customers impacted, or the manner in which the revenue deficiency is to be recovered. Edison notes that only CMA proposed to set an upper limit on the revenue shortfall of 13 to 16% over the system average percentage change resulting from this proceeding.

Edison further believes that there is no need for a "cap" on TOU-8 rates since the impact of the rate changes has already been moderated by Edison's proposed rate design. Edison also believes that a rate limiter would permit a customer to impose loads during the summer on-peak period, but escape the resulting costs imposed on Edison's system.

Edison similarly objects to the application of rate limiters to standby customers. It is Edison's position that since the profiles of standby customers' loads, in the aggregate, are very similar to those of TOU-8 customers in the aggregate, they should be fully subject to all pricing terms and conditions of the signals to customers who have chosen to self-generate and to those who are considering such a move. We believe that these charges properly take into consideration the load characteristics of the group as a whole and include fixed monthly charges needed to reflect the noncoincident demand of these customers.

The specificity in the cost to rate relationship sought by the interested parties appears to be aimed not so much at achieving cost-based rates as recognizing this customer group's "unique characteristics." We are certain that other TOU-8 customers can offer us instances in which their rates do not reflect their exact usage characteristics. While we have attempted to ensure rates that are cost-based and time-related, usage characteristics of the affected customer groups as a whole are an important consideration in ensuring that subsidization of the group by other customers does not result. To the extent that adverse bill impacts for these customers result from our adopted rate design, we find that PSD's rate limiter proposal for standby charges, discussed below, is a more appropriate means of adjusting these charges based on the standby customers' "unique characteristics."

In this regard, we note that the fact that a self-generator may have paid some costs associated with distribution and transmission facilities should not lead to the waiver of the standby charge which is based on <u>all</u> costs incurred by the utility to serve that customer. In the future, we suggest that Edison and PSD, however, continue to refine and clarify those costs are directly imposed on the system by the self-generator in receiving standby service. Edison, as stated previously, has in fact urged this course of action in asking that the Commission recognize the need for the inclusion of transmission and distribution components in the standby charge in the future.

Finally, we reject any request to "phase-in" standby charge increases. We fully concur with Edison that such a

TOU-8 schedule whenever these customers take service. Edison is again concerned with the potential of a resulting subsidy of this customer group by other customers.

Edison's greatest concerns, however, are reserved for individual rate limiters like those proposed by CMA and DGS. Edison believes that individually determined limiters would be extremely difficult and prohibitively expensive to administer.

b. <u>Discussion</u>

In D.86-12-091, we found for PG&E that, while our goal was to achieve cost-based rates, full implementation of such rates could result in severe bill impacts for some customers. We concluded that the best approach for mitigating adverse bill impacts involved adjustments to marginal cost-based demand and energy charges coupled with the use of rate limiters.

In D.86-12-091, for PG&E's mandatory large power schedule, E-20, we adopted a summer rate limiter for primary and secondary voltage customers of 1 cent/kWh above the average summer rate for the secondary voltage level. This rate limiter was found to have a 0.8% effect on industrial rates. We also adopted on-peak rate limiters based on the upper limit of the value of energy during the on-peak period at the coincident capacity cost plus the on-peak energy rate without capacity costs. (D.86-12-091, at pp. 58-59.)

In this proceeding, we similarly find that the rate limiter is an appropriate means of mitigating adverse bill impacts. By using the limiter, we are able to address this problem while still ensuring the adjustment of marginal cost-based rates which more accurately reflect the costs which the customer imposes on the utility system.

Only PSD, however, has provided us with a basis upon which to determine a specific rate limiter under any of Edison's large power schedules - in this case, for standby rates. Those parties urging the adoption of rate limiters for TOU-8 generally suggestion is appropriately reserved for such significant class rate impacts as will result to the domestic customer group from our move to an EPMC revenue allocation. As stated previously, the rate limiter proposed by PSD and discussed below is a more appropriate response to adverse bill impacts. We therefore adopt as reasonable PSD's standby rate proposal which requires the closing of Schedules SCG-1 through 3 and the establishment of Schedule S.

3. Rate Limiters

In this proceeding, three interested parties (FEA, CMA, and IU) have proposed that a "cap" be applied to the maximum effective change in TOU-8 customer bills to mitigate any adverse impacts caused by the adoption of cost-based rates for this customer group. PSD has also proposed a cap or "rate limiter" on its proposed standby charges. Edison opposes any cap on TOU-8 or standby rates.

a. Rate Limiter Proposals

FEA, CMA, and IU propose that to reduce the rate impact produced by the move toward cost-based rates a transitional "rate limiter" or maximum acceptable charge per kilowatt-hour should be adopted for the TOU-8 rate schedule. Customers whose average rate exceeds the limiter would be billed based on the limiter, rather than the filed tariff. CMA states that a phase-in of rate increases to the TOU-8 customer is required to afford that customer the opportunity to change its load patterns, based on long-standing price signals from Edison, in response to the new price signals which will result from this proceeding. CMA claims that based on PSD's and Edison's proposals, increases of between 20% and 151.1% could result for many TOU-8 customers, with one customer receiving an increase of 267.7%.

These parties also agree that the rate limiter adopted by the Commission for PG&E's large customer group in D.86-12-091 should serve as the model for the rate limiter to be considered in this proceeding. These parties cite the Commission's conclusion in have, as Edison has noted, provided no formula from which the Commission could determine those limiters or the resulting revenue impact.

We agree with these parties that the level of the rate limiter is dependent on the revenue adopted. The overall revenue allocated to customer groups in this proceeding, however, is far less than that requested by Edison. Further, our adoption of an EPMC revenue allocation will result in substantial decreases to the large power customer group. We have also rejected Edison's and PSD's request for ratcheted demand charges which should mitigate the impact of those charges on seasonal customers when their demand on the system is low.

We recognize, however, that even under these circumstances, certain customers may still be adversely impacted by our rate design adopted for TOU-8. We therefore believe it is reasonable to adopt certain rate limiters aimed at mitigating adverse bill impacts at periods of peak demand. In determining these rate limiters, we will follow the approach taken in D.86-12-091 and adopt a summer rate limiter for primary and secondary voltage customers of 1 cent/kWh above the average summer rate for the TOU-8 secondary voltage level. For on-peak rates, we will adopt rate limiters based on the value of energy during the on-peak period at the coincident capacity cost plus the on-peak energy rate without capacity costs. The revenue deficiency resulting from the imposition of these rate limiters will be spread on an EPMC basis back to all customers receiving service under TOU-8.

We also find PSD's proposed rate limiter for standby customers to be reasonable and well-supported in this record. By using a rate limiter, we are able to adjust these rates in recognition of the unique characteristics of this group of customers, while continuing to ensure rates which more accurately reflect the cost of serving these customers. Revenue deficiencies that decision that the combination of cost-based rates and a rate limiter provide customers a clear signal of future bill increases while shielding those most severely impacted from the full immediate impact of the rate change.

FEA, IU, and CMA concur that the fact that none of these parties recommended a specific level for the cap or an estimate of the revenue impact should not be a reason for rejecting a rate limiter in this proceeding. IU states that the Commission was faced with the same situation in PG&E's proceeding but was still able to impose rate limiters. FEA asserts that the absence of a recommended cap relates directly to Edison's failure to provide customer impact data as PG&E had in its proceeding. Based on the absence of the necessary information, both parties recommend that Edison be directed to work with the Commission to develop an appropriate level for the rate limiter based on the actual revenue allocated and rate structures adopted in this proceeding for TOU-8 customers. CMA states that revenue deficiencies should be reallocated to the TOU-8 class as a whole.

PSD acknowledges that an inevitable consequence of moving to marginal cost based pricing is the potential for adverse bill impacts for some customers. PSD therefore does not oppose rate limiters like those adopted for PG&E's large power customers when the rate impact is beyond a reasonable level and affects a significant number of customers.

In fact, PSD proposed such a specific rate limiter for standby charges. PSD bases its limiter on the difference in on-peak usage between firm and standby customers. According to PSD, firm customers, by taking service continually, are likely to take service during actual hours of system peak. PSD states that in contrast, there is no assurance, but only a probability, that standby customers, taking only intermittent service will take service during any hours of actual system peak. PSD notes that resulting from the adoption of PSD's proposed standby rate limiter should similarly be spread on an EPMC basis back to all large power customers served under TOU-8.

No other limitations on standby rates, i.e., mid-peak rate limiters or interruptible rate limiters for standby customers, however, are required. The rate limiters which we have adopted for all TOU-8 customers coupled with the specific rate limiter proposed by PSD for standby customers should be sufficient to mitigate any adverse rate impacts resulting from our adopted standby rates.

E. <u>Agricultural and Pumping Customer Group</u>

1. <u>Introduction</u>

Agricultural rates are a continual focus of concern for this Commission. Over the years, the Commission has attempted to respond to the needs of this major California industry which is characterized by a significant electrical requirement and diversity in load patterns. Among the industries receiving electric service from Edison, agriculture represents one for which service options provide a key to economic stability.

In response to this need legislation was adopted in 1986 to require alternative service options for agricultural customers. Specifically, Section 744 of the California Public Utilities Code provides that all California electric utilities must offer tariffs to agricultural producers, where economically and technologically feasible, which provide "optional alternative interruptible service" and "optional off-peak demand service." The latter option is to include the availability of time-differentiating meters or other measurement devices. The criteria governing these tariffs is similarly provided in Section 744. Section 744 also states that the optional rates should not be less than the cost of serving these customers.

In D.87-04-028, the Commission considered a stipulation entered between PG&E, PSD, the Farm Bureau, and the Power Users Protection Council related to an agricultural TOU rate structure.

standby customers are also capable of selecting a time of lowest cost incurrence for scheduled maintenance.

PSD has therefore proposed an "on-peak rate limiter" for standby charges to reflect the "probability" of standby customers taking service during the "on-peak" period. PSD states that it developed the limiter, which would be applied to adjust the on-peak charges otherwise applicable to a standby customer taking service, using a complex simulation model. While PSD notes that Edison has disagreed with its proposal, PSD states that Edison's witness did in fact acknowledge that standby customers should pay their "relative share of that on-peak capacity based on the probability that they may contribute to that on-peak load." (Tr. at p. 4211.)

DGS and the CSC both support the rate limiter proposed for standby customers by PSD. These parties concur in PSD's analysis that standby service is rarely required during the system's peak and that the rate limiter would reflect the utility's lower cost of supplying standby power.

Because the proposed increased in standby charges are dramatic, DGS also believes that a rate limiter is needed to avoid extreme rate impacts which would be unfair and might encourage uneconomic bypass. DGS therefore endorses both an on-peak and mid-peak rate limiter for standby customers.

The CSC believes that PSD's rate limiter is the "best effort" to develop a fair, cost-based charge for standby service. The CSC also states that Edison's rebuttal to the rate limiter focused on irrelevant and otherwise unsupported testimony that self-generators do not operate at high annual capacity factors. According to the CSC, annual capacity factors do not reflect a self-generators' capacity factors during peak hours.

In its brief, the CSC also proposed that a separate rate limiter be considered for standby customers purchasing under the I-6 interruptible schedule. Specifically, the CSC proposes the adoption of a rate limiter developed using the same methodology as

This structure, which included a series of options for agricultural service, was adopted by the Commission with certain modifications.

In this proceeding, both PSD and Edison have presented comprehensive recommendations for modifying existing agricultural rate schedules and offering new options to these customers. While these two parties disagree on certain issues, their proposals reflect a joint effort to relate agricultural rates more closely to marginal costs. Both parties have also provided options designed to meet the requirements of Section 744. PSD states that while it does not disagree with the two options proposed by Edison, PSD believes that its proposal offers a much greater number of options (9) more fully reflecting the diverse operating patterns of agricultural customers.

The only party other than Edison and PSD which actually offered testimony and a brief on agricultural rate design was ACWA. ACWA's testimony and brief focus on the demand charges proposed by Edison and PSD for the PA-1 and PA-2 schedules and the need for an optional PA-TOU schedule for all water pumpers currently served under the TOU-8 schedule.

Concerns, however, were expressed by the Farm Bureau and the Citrus Growers Cooperative regarding certain aspects of the proposed agricultural rate structure.

These concerns focus on Edison's proposal to close its GS-1 schedule to new customers. These parties claim that this change will have a significant negative impact on citrus growers who have purchased existing wind machines with the expectation of continued service under the current GS-1 schedule. Additionally, the Citrus Growers Cooperative has asked that the off-peak credit provision of Schedule PA-1 (Special Condition No.5) be reworded to allow disconnecting of load during summer months only.

Although Edison believes that appropriate price signals must be provided to citrus growers who are considering the purchase of frost protection equipment, Edison also shares the concerns of

PSD applied to the standby rates, but also taking into account the 0.75 ERI associated with the I-6 schedule.

Edison rejects all of the rate limiter proposals made by PSD and the interested parties. Edison states that with respect to the proposals of IU, FEA, and CMA, none have included a specification of the cap or an estimation of the resulting revenue shortfall, the number of customers impacted, or the manner in which the revenue deficiency is to be recovered. Edison notes that only CMA proposed to set an upper limit on the revenue shortfall of 13 to 16% over the system average percentage change resulting from this proceeding.

Edison further believes that there is no need for a "cap" on TOU-8 rates since the impact of the rate changes has already been moderated by Edison's proposed rate design. Edison also believes that a rate limiter would permit a customer to impose loads during the summer on-peak period, but escape the resulting costs imposed on Edison's system.

Edison similarly objects to the application of rate limiters to standby customers. It is Edison's position that since the profiles of standby customers' loads, in the aggregate, are very similar to those of TOU-8 customers in the aggregate, they should be fully subject to all pricing terms and conditions of the TOU-8 schedule whenever these customers take service. Edison is again concerned with the potential of a resulting subsidy of this customer group by other customers.

Edison's greatest concerns, however, are reserved for individual rate limiters like those proposed by CMA and DGS. Edison believes that individually determined limiters would be extremely difficult and prohibitively expensive to administer.

b. Discussion

In D.86-12-091, we found for PG&E that, while our goal was to achieve cost-based rates, full implementation of such rates could result in severe bill impacts for some customers. We these parties. Edison therefore recommends that these customers be placed on the proposed GS-TP schedule which will provide three additional years of service at rates similar to the current GS-1 rate. After that time, Edison states that these customers should be placed on Schedules PA-1 or PA-2 which provide cost-based rates. Edison also concurs with the change requested by the Citrus Growers Cooperative to Special Condition 5 of the PA-1 schedule.

We concur with Edison that the citrus growers should be offered an opportunity to respond to a change in rate design which could have an adverse effect on investments made in reliance on a prior rate structure. We find that Edison's suggested placement of citrus growers on the three-phase GS-TP schedule with movement to PA-1 or PA-2 after three years provides such an opportunity while moving these customers eventually to cost based rates. This change proposed by Edison along with the amendment of Special Condition 5 of PA-1 proposed by the citrus growers appropriately responds to the needs of these customers, and should be adopted.

In the following sections, we will review the parties' proposal first for changes to existing agricultural Schedules PA-1 and PA-2 and second for rate options for these customers. Within each of these sections, we will discuss each of the proposed rate structures and resolve the issues presented.

2. <u>Schedules PA-1 and PA-2</u>

Schedules PA-1 and PA-2 are the primary schedules specifically designed for agricultural customers. Schedule PA-1 is a flat rate energy schedule with a connected load charge based on the horsepower of the connected load. Schedule PA-2 is also currently a flat rate energy schedule, but provides a demand charge based on all kilowatts of billing demand, instead of a connected load charge.

For these rate schedules, as with those which we have previously discussed, Edison and PSD were able to reach substantial agreement on the appropriate rate structures. For PA-1, the concluded that the best approach for mitigating adverse bill impacts involved adjustments to marginal cost-based demand and energy charges coupled with the use of rate limiters.

In D.86-12-091, for PG&E's mandatory large power schedule, E-20, we adopted a summer rate limiter for primary and secondary voltage customers of 1 cent/kWh above the average summer rate for the secondary voltage level. This rate limiter was found to have a 0.8% effect on industrial rates. We also adopted on-peak rate limiters based on the upper limit of the value of energy during the on-peak period at the coincident capacity cost plus the on-peak energy rate without capacity costs. (D.86-12-091, at pp. 58-59.)

In this proceeding, we similarly find that the rate limiter is an appropriate means of mitigating adverse bill impacts. By using the limiter, we are able to address this problem while still ensuring the adjustment of marginal cost-based rates which more accurately reflect the costs which the customer imposes on the utility system.

Only PSD, however, has provided us with a basis upon which to determine a specific rate limiter under any of Edison's large power schedules - in this case, for standby rates. Those parties urging the adoption of rate limiters for TOU-8 generally have, as Edison has noted, provided no formula from which the Commission could determine those limiters or the resulting revenue impact.

We agree with these parties that the level of the rate limiter is dependent on the revenue adopted. The overall revenue allocated to customer groups in this proceeding, however, is far less than that requested by Edison. Further, our adoption of an EPMC revenue allocation will result in substantial decreases to the large power customer group. We have also rejected Edison's and PSD's request for ratcheted demand charges which should mitigate parties are in complete agreement. Despite Edison's original proposal to close PA-1 to new customers, Edison subsequently agreed with PSD to keep this schedule open for three-phase agricultural customers. For PA-2, the only disagreement between the parties on rate structure involves the appropriate customer charge.

a. <u>Customer Charge</u>

Edison and PSD agree on setting the proposed PA-1 customer charge at $10 per month. For the PA-2 schedule, Edison has proposed a customer charge of $10 per month, while PSD has proposed a customer charge of $30.22 per month. Edison agrees with PSD that the PA-2 customer charge could and probably should be higher than the PA-1 customer charge based on the marginal customer costs for PA-2 customers being approximately twice that for PA-1 customers. Edison therefore states that it would not oppose a compromise of $20 per month for this schedule.

PSD bases its recommendation of a $30 customer charge on the need to reflect marginal customer costs. To this end, PSD states that its proposed customer charge would collect more than 50% of the marginal customer cost for PA-2 customers. PSD does not believe that Edison's proposed compromise, while recognizing the discrepancy in marginal customer costs between the two schedules, goes far enough in moving this charge toward a full marginal cost basis. PSD notes that by not reflecting these costs in the customer charge these costs will be recovered in a component (i.e., energy charges) unrelated to their causation.

We find that PSD's recommended customer charge is consistent with our policy to recover fixed cost components in fixed charges, with those charges based on marginal costs. The impact of a three-fold increase in a customer charge could, however, have the effect of causing customer confusion regarding the need for such a significant increase in a fixed cost. We would also be offering little notice or opportunity for the PA-2 customer to respond to this change.

the impact of those charges on seasonal customers when their demand on the system is low.

We recognize, however, that even under these circumstances, certain customers may still be adversely impacted by our rate design adopted for TOU-8. We therefore believe it is reasonable to adopt certain rate limiters aimed at mitigating adverse bill impacts at periods of peak demand. In determining these rate limiters, we will follow the approach taken in D.86-12-091 and adopt a summer rate limiter for primary and secondary voltage customers of 1 cent/kWh above the average summer rate for the TOU-8 secondary voltage level, excluding customer charges. The revenue deficiency resulting from the imposition of this rate limiter will be spread on an EPMC basis back to primary and secondary customers receiving service under TOU-8.

For on-peak rates for TOU-8 and standby customers, where applicable, we also find PSD's proposed on-peak rate limiter to be reasonable and well-supported in this record and will adopt rate limiters based on the value of energy during the on-peak period at the coincident capacity cost plus the on-peak energy cost, adjusted to EPMC. By using a rate limiter, we are able to adjust these rates in recognition of the unique characteristics of this group of customers, while continuing to ensure rates which more accurately reflect the cost of serving these customers. Revenue deficiencies resulting from the adoption of PSD's proposed on-peak rate limiter should similarly be spread on an EPMC basis back to all large power customers served under TOU-8, but these customers should pay no less than their customer cost.

No other limitations on standby rates, i.e., mid-peak rate limiters or interruptible rate limiters for standby customers, however, are required. The rate limiters which we have adopted for all TOU-8 customers coupled with the specific rate limiter proposed by PSD for standby customers should be sufficient to mitigate any adverse rate impacts resulting from our adopted standby rates.

We therefore find reasonable and adopt Edison's proposed compromise of a $20 per month customer charge for the PA-2 schedule. This charge will reflect the difference between marginal customer costs between the PA-1 and PA-2 schedules and will move the PA-2 schedule closer to its marginal customer cost responsibility. These results will also be achieved without as significant an adverse impact as the charge proposed by PSD.

b. Demand Charge

Edison and PSD agree on setting the PA-1 connect charge at $2 per HP. The parties also agree on setting the proposed PA-2 time-related demand charge at $6.00 per kW in the summer with no charge in the winter. The non-time related demand charge would be set at $2.30 per kW of the current billing period demand or 50% of the highest demand over the previous 11 months whichever is greater.

ACWA opposes the noncoincident demand charges at the levels proposed by either Edison or PSD. According to ACWA, the revenues which would have been collected by the noncoincident demand charges should be collected through on-peak demand charges.

If the Commission determines that noncoincident demand charges are appropriate, ACWA asks that these charges be set at half the level proposed by Edison and PSD to account for longer-lived rural distribution equipment. ACWA asserts that it is inappropriate to assess a noncoincident demand charge at system average marginal cost because rural lines are sized for a lower coincidence factor than urban lines. According to ACWA, the Edison and PSD rate designs also wrongly presume that the amount of electrical diversity on rural lines is identical to heavily-industrialized urban lines.

As a first item in addressing the demand charges proposed by Edison and PSD, we reference our previous finding in this decision that "ratchets," which act to maintain demand charges at a constant level even during periods of low load, are not to be used

E. Agricultural and Pumping Customer Group

1. Introduction

Agricultural rates are a continual focus of concern for this Commission. Over the years, the Commission has attempted to respond to the needs of this major California industry which is characterized by a significant electrical requirement and diversity in load patterns. Among the industries receiving electric service from Edison, agriculture represents one for which service options provide a key to economic stability.

In response to this need legislation was adopted in 1986 to require alternative service options for agricultural customers. Specifically, Section 744 of the California Public Utilities Code provides that all California electric utilities must offer tariffs to agricultural producers, where economically and technologically feasible, which provide "optional alternative interruptible service" and "optional off-peak demand service." The latter option is to include the availability of time-differentiating meters or other measurement devices. The criteria governing these tariffs is similarly provided in Section 744. Section 744 also states that the optional rates should not be less than the cost of serving these customers.

In D.87-04-028, the Commission considered a stipulation entered between PG&E, PSD, the Farm Bureau, and the Power Users Protection Council related to an agricultural TOU rate structure. This structure, which included a series of options for agricultural service, was adopted by the Commission with certain modifications.

In this proceeding, both PSD and Edison have presented comprehensive recommendations for modifying existing agricultural rate schedules and offering new options to these customers. While these two parties disagree on certain issues, their proposals reflect a joint effort to relate agricultural rates more closely to marginal costs. Both parties have also provided cptions designed to meet the requirements of Section 744. PSD states that while it in calculating demand charges. This conclusion, the reasoning for which is reviewed at greater length in our discussion of demand charges for the TOU-8 schedule, is equally applicable to the agricultural Schedule PA-2.

While our goal is to reflect fixed costs in fixed charges, we also wish to ensure that the fixed costs being included in those charges relate in fact to the costs which the customer imposes on the system. We find that agricultural customers do impose noncoincident demand costs on the system and should be charged rates in accordance with those costs. We further find, however, that ACWA's testimony has demonstrated that PSD's and Edison's proposed noncoincident demand charges reflect costs imposed by urban customers, rather than the rural customers for whom the agricultural schedules have been developed.

For this reason, we will adopt ACWA's proposal to reduce PSD's and Edison's proposed noncoincident demand charges for PA-2 by one-half. As these costs are unrelated to demand, as ACWA's position suggests, it would, however, be inappropriate for them to be reflected in on-peak demand charges as ACWA has recommended.

With the exception of these changes, we otherwise find reasonable the demand charges proposed by Edison and PSD. Those charges, as modified above, should therefore be adopted.

c. Energy Charge

Edison and PSD agree that there should be no seasonal differentiation of the PA-1 and PA-2 energy charges. PA-1 energy charges are proposed by these parties to be set residually to collect the revenue requirement not collected through the customer or connection charges. The PA-2 energy rate is proposed to be a blocked energy rate set at 5.0 cents/kWh for all kWh in excess of 300 kWh/kW. The first block energy rate is proposed to be set to collect the remaining revenue requirement not recovered through the customer or connection charges. The first block energy rate is proposed to be set to collect the remaining revenue requirement not recovered through the other rate components.

does not disagree with the two options proposed by Edison, PSD believes that its proposal offers a much greater number of options (9) more fully reflecting the diverse operating patterns of agricultural customers.

The only party other than Edison and PSD which actually offered testimony and a brief on agricultural rate design was ACWA. ACWA's testimony and brief focus on the demand charges proposed by Edison and PSD for the PA-1 and PA-2 schedules and the need for an optional PA-TOU schedule for all water pumpers currently served under the TOU-8 schedule.

Concerns, however, were expressed by the Farm Bureau and the Citrus Growers Cooperative regarding certain aspects of the proposed agricultural rate structure.

These concerns focus on Edison's proposal to close its GS-1 schedule to new customers. These parties claim that this change will have a significant negative impact on citrus growers who have purchased existing wind machines with the expectation of continued service under the current GS-1 schedule. Additionally, the Citrus Growers Cooperative has asked that the off-peak credit provision of Schedule PA-1 (Special Condition No.5) be reworded to allow disconnecting of load during summer months only.

Although Edison believes that appropriate price signals must be provided to citrus growers who are considering the purchase of frost protection equipment, Edison also shares the concerns of these parties. Edison therefore recommends that these customers be placed on the proposed GS-TP schedule which will provide three additional years of service at rates similar to the current GS-1 rate. After that time, Edison states that these customers should be placed on Schedules PA-1 or PA-2 which provide cost-based rates. Edison also concurs with the change requested by the Citrus Growers Cooperative to Special Condition 5 of the PA-1 schedule.

We concur with Edison that the citrus growers should be offered an opportunity to respond to a change in rate design which

We find reasonable the energy charges for the PA-1 and PA-2 schedules proposed by Edison and PSD. These charges, based on sound rate design principles, were not challenged by any other party and should be adopted.

3. Agricultural Rate Options

Agricultural rate options have been proposed by three parties in this proceeding: Edison, as described in its Supplemental Exhibit on Agricultural Rate Options (Ex.165), PSD, as presented in its original rate design exhibit (Ex. 61), and ACWA, as included in Exhibit 96. These proposals are summarized below followed by our resolution of the issues presented.

a. Parties Positions

Edison states that its proposed agricultural rate options are similar to those proposed by PSD. These options include an on-peak time period option (existing Schedule TOU-PA-2 with a six-hour or a four-hour summer on-peak period) and a three-day option (proposed Schedule TOU-PA-3D with a split week option providing rate differentials for three consecutive days (Monday through Wednesday or Wednesday through Friday)). Edison states that these options differ from PSD's proposals in that the options do not include a qualifying criteria of 35 kW for demand metered options, and do permit large customers (above 35 kW) to choose the connect load basis TOU option.

Edison states that it has also proposed an interruptible option which would be available to all agricultural and pumping customers. According to Edison, this option would not only provide some measure of dispatchable load, but would also permit Edison to retain existing sales which might otherwise be lost through conversion to diesel pumping. Edison states that these objectives can only be accomplished, however, if the proposed level of credit (1.5 cents/kWh) is permitted.

Edison states that its proposed options for agricultural customers were developed jointly with a working group of farmers could have an adverse effect on investments made in reliance on a prior rate structure. We find that Edison's suggested placement of citrus growers on the three-phase GS-TP schedule with movement to PA-1 or PA-2 after three years provides such an opportunity while moving these customers eventually to cost based rates. This change proposed by Edison along with the amendment of Special Condition 5 of PA-1 proposed by the citrus growers appropriately responds to the needs of these customers, and should be adopted. Since the load of most citrus growers exceeds 75 kW, we will direct Edison to reflect a special condition comparable to specal condition S for PA-2.

In the following sections, we will review the parties' proposal first for changes to existing agricultural Schedules PA-1 and PA-2 and second for rate options for these customers. Within each of these sections, we will discuss each of the proposed rate structures and resolve the issues presented.

2. Schedules PA-1 and PA-2

Schedules PA-1 and PA-2 are the primary schedules specifically designed for agricultural customers. Schedule PA-1 is a flat rate energy schedule with a connected load charge based on the horsepower of the connected load. Schedule PA-2 is also currently a flat rate energy schedule, but provides a demand charge based on all kilowatts of billing demand, instead of a connected load charge.

For these rate schedules, as with those which we have previously discussed, Edison and PSD were able to reach substantial agreement on the appropriate rate structures. For PA-1, the parties are in complete agreement. Despite Edison's original proposal to close PA-1 to new customers, Edison subsequently agreed with PSD to keep this schedule open for three-phase agricultural customers. For PA-2, the only disagreement between the parties on rate structure involves the appropriate customer charge.

representing all agricultural areas within Edison's service territory. In contrast, Edison believes that PSD's proposed options merely represent a "carry-over" from the PG&E general rate case and were not designed to meet the requirements of Edison's agricultural customers. Edison also believes that PSD's proposed options are much more restrictive than those proposed by Edison, especially with regard to smaller customers.

PSD states that it has no criticism of Edison's time-of-use proposals which, as Edison has noted, almost completely conform with two of PSD's proposed options. PSD's only objection is Edison providing a demand charge for TOU-PA-2 which differs from the level set for PA-2. PSD asserts that demand charges should be the same for these two rate schedules which reflect similar size and cost causation characteristics.

PSD' states that its primary objection to Edison's proposal is that it does not offer a sufficient number of options. PSD states that it has proposed nine schedules, including a super off-peak rate option for agricultural customers. Each of these schedules has three components -- customer charges, demand charges and energy rates -- developed consistent with overall PSD rate design policies.

PSD states that eight options relate to four basic schedules which are offered separately to customers with demands less than 35 kW and those with demands greater than 35 kW. These schedules include the following:

1. TOU-PA: a standard TOU schedule.

2. TOU-PA (SPLIT WEEK): for agricultural customers who need a continual pumping run to irrigate crops and are extremely limited by or cannot operate outside TOU peak periods.

3. TOU-PA (REDUCED PEAK HOURS): For customers who must irrigate during daylight hours, but can choose shorter peak periods to suit

a. Customer Charge

Edison and PSD agree on setting the proposed PA-1 customer charge at $10 per month. For the PA-2 schedule, Edison has proposed a customer charge of $10 per month, while PSD has proposed a customer charge of $30.22 per month. Edison agrees with PSD that the PA-2 customer charge could and probably should be higher than the PA-1 customer charge based on the marginal customer costs for PA-2 customers being approximately twice that for PA-1 customers. Edison therefore states that it would not oppose a compromise of $20 per month for this schedule.

PSD bases its recommendation of a $30 customer charge on the need to reflect marginal customer costs. To this end, PSD states that its proposed customer charge would collect more than 50% of the marginal customer cost for PA-2 customers. PSD does not believe that Edison's proposed compromise, while recognizing the discrepancy in marginal customer costs between the two schedules, goes far enough in moving this charge toward a full marginal cost basis. PSD notes that by not reflecting these costs in the customer charge these costs will be recovered in a component (i.e., energy charges) unrelated to their causation.

We find that PSD's recommended customer charge is consistent with our policy to recover fixed cost components in fixed charges, with those charges based on marginal costs. The impact of a three-fold increase in a customer charge could, however, have the effect of causing customer confusion regarding the need for such a significant increase in a fixed cost. We would also be offering little notice or opportunity for the PA-2 customer to respond to this change.

We therefore find reasonable and adopt Edison's proposed compromise of a $20 per month customer charge for the PA-2 schedule. This charge will reflect the difference between marginal customer costs between the PA-1 and PA-2 schedules and will move the PA-2 schedule closer to its marginal customer cost their operations while shifting peak use among hours of the peak period.

4. TOU-PA (MINIMUM BILL): developed in response to evidence from Edison and growers that system bypass with diesel engine pumping may be economic for high load factor customers with the current average electric rates.

PSD states that its ninth option is the super off-peak rate, TOU-PA-SOP. This schedule is proposed to be based on TOU-8-SOP, but with a simpler structure for agricultural customers.

PSD states that its basis for providing separate sets of schedules for agricultural customers corresponding to their demand level relates to the need to ensure that connected load based schedules are made available only to customers below 35 kW. PSD notes that the Edison witness acknowledged the correctness of PSD's assumption, on which its differentiation in schedules is based. This assumption is that PA-1 and PA-2 customers can be distinguished by the level of their demand, with the demand of PA-2 customer exceeding 35 kW and the demand of PA-1 customers being less than 35 kW.

PSD also responded to Edison's criticism that its recommendations are merely a "carry over" from those adopted for PG&E's agricultural customers. PSD states that while it used the same considerations raised in the PG&E proceeding in developing its agricultural rate options for Edison, the options were in fact tailored to meet the needs of Edison's customers.

In its Exhibit 96, ACWA urged the Commission to adopt a PA-TOU schedule which would be optional for all water pumpers currently served under the TOU-8 rate schedule. According to ACWA, PA-TOU would be identical to TOU-8 in its base, but would permit selection of a narrower on-peak period with a higher demand cost commensurate with the greater coincidence with system peak. PA-TOU would, in ACWA's opinion, offer a realistic opportunity for water pumpers to respond to TOU rates.

responsibility. These results will also be achieved without as significant an adverse impact as the charge proposed by PSD.

b. Demand Charge

Edison and PSD agree on setting the PA-1 connect charge at $2 per HP. The parties also agree on setting the proposed PA-2 time-related demand charge at $6.00 per kW in the summer with no charge in the winter. The non-time related demand charge would be set at $2.30 per kW of the current billing period demand or 50% of the highest demand over the previous 11 months whichever is greater.

ACWA opposes the noncoincident demand charges at the levels proposed by either Edison or PSD. According to ACWA, the revenues which would have been collected by the noncoincident demand charges should be collected through on-peak demand charges.

If the Commission determines that noncoincident demand charges are appropriate, ACWA asks that these charges be set at half the level proposed by Edison and PSD to account for longer-lived rural distribution equipment. ACWA asserts that it is inappropriate to assess a noncoincident demand charge at system average marginal cost because rural lines are sized for a lower coincidence factor than urban lines. According to ACWA, the Edison and PSD rate designs also wrongly presume that the amount of electrical diversity on rural lines is identical to heavily-industrialized urban lines.

As a first item in addressing the demand charges proposed by Edison and PSD, we reference our previous finding in this decision that "ratchets," which act to maintain demand charges at a constant level even during periods of low load, are not to be used in calculating demand charges. This conclusion, the reasoning for which is reviewed at greater length in our discussion of demand charges for the TOU-8 schedule, is equally applicable to the agricultural Schedule PA-2.

Specifically, ACWA's proposed PA-TOU would permit the water pumper to choose 2, 3, 4, or 5 hours on-peak as an alternative to the full 6-hour (12:00 p.m. to 6:00 p.m.) period. ACWA states that PA-TOU would differ from other Edison service reliability options in that the penalty (on-peak) period would not last as long as a curtailable or interruptible period. The shorter period is necessary, according to ACWA, due to the inordinately high cost of additional storage, mains, and pumps.

With respect to the agricultural rate options proposed by Edison and PSD, ACWA states that the menu of agricultural rates proposed by Edison in Exhibit 165 is not as comprehensive as that adopted in D.87-04-028 for PG&E. ACWA therefore supports PSD's proposed options which ACWA finds comparable to those adopted for PG&E.

b. <u>Discussion</u>

As we have indicated previously in this order, our reliance in this proceeding on recent rate decisions of other utilities is largely due to the need to ensure the application of consistent rate design policies to all utilities which we regulate. We assure Edison and its agricultural customers, however, that the specific needs of Edison's customers, to the extent that they differ from that of customers within another utility's service territory, are considered in the rate design which we adopt.

In this case, PSD has responded to our most recent rate design policy applied to agricultural rates. That policy, reflected in D.87-04-028, is to provide greater control to agricultural customers over their energy usage and costs consistent with the needs and usage characteristics of those customers and the statutory mandate of Section 744.

We find therefore that the PSD proposal, which includes the options recommended by Edison, as well as several more options for agricultural customers is reasonable and should be adopted. We also believe that PSD has provided a reasonable basis for

While our goal is to reflect fixed costs in fixed charges, we also wish to ensure that the fixed costs being included in those charges relate in fact to the costs which the customer imposes on the system. We find that agricultural customers do impose noncoincident demand costs on the system and should be charged rates in accordance with those costs. We further find, however, that ACWA's testimony has demonstrated that PSD's and Edison's proposed noncoincident demand charges reflect costs imposed by urban customers, rather than the rural customers for whom the agricultural schedules have been developed.

For this reason, we will adopt ACWA's proposal to reduce PSD's and Edison's proposed noncoincident demand charges for PA-2 by one-half, with a similar reduction, for purposes of consistency, in the PA-1 connect charge. As these costs are unrelated to time-related demand, as ACWA's position suggests, it would, however, be inappropriate for them to be reflected in on-peak demand charges as ACWA has recommended.

With the exception of these changes, we otherwise find reasonable the demand charges proposed by Edison and PSD. Those charges, as modified above, should therefore be adopted.

c. Energy Charge

Edison and PSD agree that there should be no seasonal differentiation of the PA-1 and PA-2 energy charges. PA-1 energy charges are proposed by these parties to be set residually to collect the revenue requirement not collected through the customer or connection charges. The PA-2 energy rate is proposed to be a blocked energy rate set at 5.0 cents/kWh for all kWh in excess of 300 kWh/kW. The first block energy rate is proposed to be set to collect the remaining revenue requirement not recovered through the other rate components.

We find reasonable the energy charges for the PA-1 and PA-2 schedules proposed by Edison and PSD. These charges, based on distinguishing between customers based on their demand level being in excess of or less than 35 kW. This distinction is based on and appears to be reflected in the demand levels of customers choosing either the PA-1 (less than 35 kW) or PA-2 (above 35 kW) schedules.

With respect to ACWA's proposed PA-TOU schedule, in D.87-04-028 we found that agricultural TOU rate options appeared reasonable for some ACWA accounts. We wish to ensure in this proceeding, as we did for PG&E, however, that service under these schedules is reserved for purposes related to agriculture. We will therefore apply the same criteria adopted in D.87-04-028 that service under this type of schedule be limited to customers for whom at least 70% of the water pumped by an individual account is for agricultural purposes

We therefore find reasonable the transfer of ACWA accounts which meet this standard to the agricultural class. Under these circumstances, such customers will be able to take advantage of the adopted TOU-PA Reduced Peak Hours schedule which we believe addresses the need of agricultural water pumpers for a service option based on narrower time periods than are currently available under TOU-8. It is therefore unnecessary to adopt the PA-TOU option proposed by ACWA.

F. Street and Area Lighting Customer Group

1. Introduction

Several of the issues which have been raised with respect to streetlighting by Edison, PSD, and CAL-SLA have been previously addressed in this decision. These issues include our decision to include marginal customer costs and energy charges associated with streetlighting in the revenue allocation process. In this portion of our decision, we will focus on the specific recommendations made by Edison, PSD, and CAL-SLA with respect to the street and area lighting schedules LS-1 (Edison-owned street lamps), LS-2 (customer-owned street lamps), LS-3 (metered streetlight service), OL-1 (outdoor lighting), and DWL (domestic walkway).

sound rate design principles, were not challenged by any other party and should be adopted.

3. Agricultural Rate Options

Agricultural rate options have been proposed by three parties in this proceeding: Edison, as described in its Supplemental Exhibit on Agricultural Rate Options (Ex.165), PSD, as presented in its original rate design exhibit (Ex. 61), and ACWA, as included in Exhibit 96. These proposals are summarized below followed by our resolution of the issues presented.

a. Parties Positions

Edison states that its proposed agricultural rate options are similar to those proposed by PSD. These options include an on-peak time period option (existing Schedule TOU-PA-2 with a six-hour or a four-hour summer on-peak period) and a three-day option (proposed Schedule TOU-PA-3D with a split week option providing rate differentials for three consecutive days (Monday through Wednesday or Wednesday through Friday)). Edison states that these options differ from PSD's proposals in that the options do not include a qualifying criteria of 35 kW for demand metered options, and do permit large customers (above 35 kW) to choose the connect load basis TOU option.

Edison states that it has also proposed an interruptible option which would be available to all agricultural and pumping customers. According to Edison, this option would not only provide some measure of dispatchable load, but would also permit Edison to retain existing sales which might otherwise be lost through conversion to diesel pumping. Edison states that these objectives can only be accomplished, however, if the proposed level of credit (1.5 cents/kWh) is permitted.

Edison states that its proposed options for agricultural customers were developed jointly with a working group of farmers representing all agricultural areas within Edison's service territory. In contrast, Edison believes that PSD's proposed

Before we consider those issues, we note that PSD has expressed concern regarding the amount of time and effort devoted to streetlighting issues when only one characteristic distinguishes this class from other customer groups. That characteristic, according to PSD, is that certain customers in the streetlighting class rent their streetlights from Edison. PSD believes that this characteristic does not justify a totally different rate design approach than that applied to other customer groups. PSD asserts that the same basic, sound economic principles which guide the rate structures of other schedules should therefore be applied to the rate design adopted for streetlighting.

With this last statement, we agree. While the usage characteristics and other unique features of streetlighting customers should be considered in rate design, recognition of those characteristics do not require a wholesale departure from our adopted rate design philosophy. We believe that these customers can benefit from and should be charged rates which reflect the costs which these customers impose on the utility system. Our inclusion of streetlighting, with respect to the energy component of streetlight charges, and streetlighting marginal customer costs in the revenue allocation process are a recognition that these customers, despite unique traits, also share characteristics common to all other Edison customers.

As a frame of reference for our analysis of the various streetlighting issues, we also wish to note that in Edison's last general rate case (D.84-12-068), we directed Edison for this proceeding to undertake a current cost of service study for streetlighting. Additionally, Edison was to provide alternative rate designs for streetlighting reflecting the "additive" and the "unbundled" approaches. The "additive" approach to rate design essentially requires each of the cost components of the total rate for the streetlight schedules to be identified. With these tools, the Commission concluded that revisions to the streetlighting options merely represent a "carry-over" from the PG&E general rate case and were not designed to meet the requirements of Edison's agricultural customers. Edison also believes that PSD's proposed options are much more restrictive than those proposed by Edison, especially with regard to smaller customers.

PSD states that it has no criticism of Edison's time-of-use proposals which, as Edison has noted, almost completely conform with two of PSD's proposed options. PSD's only objection is Edison providing a demand charge for TOU-PA-2 which differs from the level set for PA-2. PSD asserts that demand charges should be the same for these two rate schedules which reflect similar size and cost causation characteristics.

PSD' states that its primary objection to Edison's proposal is that it does not offer a sufficient number of options. PSD states that it has proposed nine schedules, including a super off-peak rate option for agricultural customers. Each of these schedules has three components -- customer charges, demand charges and energy rates -- developed consistent with overall PSD rate design policies.

PSD states that eight options relate to four basic schedules which are offered separately to customers with demands less than 35 kW and those with demands greater than 35 kW. These schedules include the following:

1. TOU-PA: a standard TOU schedule.

2. TOU-PA (SPLIT WEEK): for agricultural customers who need a continual pumping run to irrigate crops and are extremely limited by or cannot operate outside TOU peak periods.

3. TOU-PA (REDUCED PEAK HOURS): For customers who must irrigate during daylight hours, but can choose shorter peak periods to suit their operations while shifting peak use among hours of the peak period.

schedules could be undertaken. We note that in this proceeding Edison has responded to both of these orders which are in keeping with our goal of providing cost-based, unbundled rates.

2. Cost of Service Study

CAL-SLA asserts that Edison's cost of service study for streetlighting fails to comply with D.86-12-068. CAL-SLA believes that Edison has interpreted the Commission's mandate to perform a historical cost analysis as permission to undertake a Reproduction Costs New analysis. CAL-SLA asserts that the proper approach would have been to reflect an Original Cost Less Depreciation (OCLD) analysis.

Edison objects to CAL-SLA's criticism of its cost study as unfounded. Edison states that it in fact performed its study the only way possible with the data currently available. Additionally, Edison cites page 370 of D.84-12-068 as requiring that the cost of service study for the streetlighting customer class be based on historical costs, if adequate records were available, or "build up" costs.

Edison states that its asset accounts, in keeping with the FERC Uniform System of Accounts, include none that are exclusively for streetlights and do not contain any reserve for depreciation as implied by CAL-SLA. Edison also notes that a OCLD figure is not readily available to Edison.

We find that Edison's cost of service study is in keeping with our directives in D.84-12-068. A Replacement Cost New methodology was an appropriate basis on which to develop that study.

3. Energy and Demand Charges

In this proceeding, Edison states that it has responded to the directives of D.84-12-068 by proposing rate levels and rate design for streetlighting based on a cost of service analysis and reliance on both the additive and unbundled rate design approaches. Edison believes that the development by PSD and CAL-SLA of energy

4. TOU-PA (MINIMUM BILL): developed in response to evidence from Edison and growers that system bypass with diesel engine pumping may be economic for high load factor customers with the current average electric rates.

PSD states that its ninth option is the super off-peak rate, TOU-PA-SOP. This schedule is proposed to be based on TOU-8-SOP, but with a simpler structure for agricultural customers.

PSD states that its basis for providing separate sets of schedules for agricultural customers corresponding to their demand level relates to the need to ensure that connected load based schedules are made available only to customers below 35 kW. PSD notes that the Edison witness acknowledged the correctness of PSD's assumption, on which its differentiation in schedules is based. This assumption is that PA-1 and PA-2 customers can be distinguished by the level of their demand, with the demand of PA-2 customer exceeding 35 kW and the demand of PA-1 customers being less than 35 kW.

PSD also responded to Edison's criticism that its recommendations are merely a "carry over" from those adopted for PG&E's agricultural customers. PSD states that while it used the same considerations raised in the PG&E proceeding in developing its agricultural rate options for Edison, the options were in fact tailored to meet the needs of Edison's customers.

In its Exhibit 96, ACWA urged the Commission to adopt a PA-TOU schedule which would be optional for all water pumpers currently served under the TOU-8 rate schedule. According to ACWA, PA-TOU would be identical to TOU-8 in its base, but would permit selection of a narrower on-peak period with a higher demand cost commensurate with the greater coincidence with system peak. PA-TOU would, in ACWA's opinion, offer a realistic opportunity for water pumpers to respond to TOU rates.

Specifically, ACWA's proposed PA-TOU would permit the water pumper to choose 2, 3, 4, or 5 hours on-peak as an and demand rates for streetlights based on an EPMC allocation is contrary to the Commission's directives in D.84-12-068 which excluded streetlighting from the marginal cost revenue allocation process.

In calculating energy and demand charges for streetlights, Edison states that it based these rates on a weighted average TOU-GS rate. In addition to the weighted average TOU-GS rate, $2,500,000 of unallocated costs were spread on an equal-cents-per kWh basis for all street and area lighting customers. Edison states that its reliance of the TOU-GS rate is based on the reasoning that, if streetlight rates were eliminated, the streetlight customer would most likely be served under a general service tariff along with other customers of similar size and load shapes. According to Edison, the TOU-GS schedule seemed to be the most likely general service tariff under which streetlighting customers would be served under these circumstances due to the primarily off-peak usage of streetlights.

Edison questions the results of the PSD and CAL-SLA proposals which cut existing energy rates in half for all customers in the streetlight group in the face of rate increases to all other classes. Edison believes that there should be some relationship between the rates charged for streetlighting and those charged others for similar service (i.e., TOU-GS).

As noted by Edison, PSD and CAL-SLA advocate establishing energy charges for streetlighting on an EPMC basis. PSD recommends that an additional 5% of the developed rate be added to reflect miscellaneous streetlight costs identified by Edison. PSD believes that the EPMC approach which it advocates provides the proper price signals for streetlight customers and ensures uniformity in the rate design principles applied to all of Edison's customers.

PSD believes that Edison's reliance on the TOU-GS schedule as the basis for its streetlighting rate is unjustified. Edison's arguments regarding the size similarities between the alternative to the full 6-hour (12:00 p.m. to 6:00 p.m.) period. ACWA states that PA-TOU would differ from other Edison service reliability options in that the penalty (on-peak) period would not last as long as a curtailable or interruptible period. The shorter period is necessary, according to ACWA, due to the inordinately high cost of additional storage, mains, and pumps.

With respect to the agricultural rate options proposed by Edison and PSD, ACWA states that the menu of agricultural rates proposed by Edison in Exhibit 165 is not as comprehensive as that adopted in D.87-04-028 for PG&E. ACWA therefore supports PSD's proposed options which ACWA finds comparable to those adopted for PG&E.

b. <u>Discussion</u>

As we have indicated previously in this order, our reliance in this proceeding on recent rate decisions of other utilities is largely due to the need to ensure the application of consistent rate design policies to all utilities which we regulate. We assure Edison and its agricultural customers, however, that the specific needs of Edison's customers, to the extent that they differ from that of customers within another utility's service territory, are considered in the rate design which we adopt.

In this case, PSD has responded to our most recent rate design policy applied to agricultural rates. That policy, reflected in D.87-04-028, is to provide greater control to agricultural customers over their energy usage and costs consistent with the needs and usage characteristics of those customers and the statutory mandate of Section 744. We find that PSD's proposal meets and exceeds the minimum requirements of that statute.

We find therefore that the PSD proposal, which includes the options recommended by Edison, as well as several more options for agricultural customers is reasonable and should be adopted. We also believe that PSD has provided a reasonable basis for distinguishing between customers based on their demand level being streetlight and TOU-GS customer are, according to PSD, invalid. PSD asserts that the only specific link found by Edison between these two types of customers was that the average size of a streetlight customer was around 300 lamps. PSD states that the fallacy of Edison's logic can be seen in assuming that a customer with 3,000 streetlights would be analogous to a TOU-8 customer, while one with 10 streetlights would be analogous to a domestic customer.

PSD asserts that in fact Edison has provided no basis for asserting that the costs imposed on its system by a streetlight customer bear any relation to those imposed by a TOU-GS customer. Further, PSD states that there is absolutely no similarity between the load profile of these two customer types. The determination of load profile requires, in PSD's opinion, an examination of the profile of the entire class which for TOU-GS would include extensive on-peak usage that is absent from the load profile of streetlight customers. For the streetlight customer, PSD cites the testimony of Edison's own witness that streetlights are characterized "by a uniform load curve, the bulk of which is in the off-peak and mid-peak areas with a small portion in the on-peak area." (Tr. at p. 4019.)

CAL-SLA concurs with PSD's assertion that the evidence does not support Edison's proposed energy charge. Like PSD, CAL-SLA questions Edison's reliance on a schedule (TOU-GS) which includes customers whose load in no way reflects the usage characteristics of the streetlight customer group. If TOU-GS is to be used, CAL-SLA questions why the TOU-GS-SOP (super off peak) rate was not selected since such a rate schedule would be more consistent with the usage patterns of a streetlight customer.

CAL-SLA also questions Edison's proposal to allocate $2.5 million on an equal cents per kilowatt-hour basis to the streetlight class as a whole and not to the specific schedules to which these costs can be attributed. CAL-SLA further asserts that in excess of or less than 35 kW. This distinction is based on and appears to be reflected in the demand levels of customers choosing either the PA-1 (less than 35 kW) or PA-2 (above 35 kW) schedules. Edison, however, should be afforded a reasonable period of time to inform its agricultural and pumping customers of this distinction based on connected load and to install the required metering. These tariff options should therefore be implemented no later than June 1, 1988.

With respect to ACWA's proposed PA-TOU schedule, in D.87-04-028 we found that agricultural TOU rate options appeared reasonable for some ACWA accounts. We wish to ensure in this proceeding, as we did for PG&E, however, that service under these schedules is reserved for purposes related to agriculture. We will therefore apply the same criteria adopted in D.87-04-028 that service under this type of schedule be limited to customers for whom at least 70% of the water pumped by an individual account is for agricultural purposes

We therefore find reasonable the mandatory transfer of ACWA accounts and other large pumping accounts which meet this standard from TOU-8 to the agricultural class. Under these circumstances, such customers will be able to take advantage of the adopted TOU-PA Reduced Peak Hours schedule which we believe addresses the need of agricultural water pumpers for a service option based on narrower time periods than are currently available under TOU-8. It is therefore unnecessary to adopt the PA-TOU option proposed by ACWA.

In evaluating the proposed rate design for the agricultural class, we note the significant contribution made by the members of PSD and the employees of Edison who developed and substantiated creative and responsive rate options where none existed before. Specifically, we find these adopted schedules to be fully in accord with the purpose of Public Utilities Code Section 744. This section requires time-differentiated off-peak

Edison has failed to present the complete factual data necessary for a showing to justify the inclusion of these unallocated charges in rates.

We concur with PSD's and CAL-SLA's recommendation that streetlight energy and demand charges should be based on marginal costs. This approach is consistent not only with the rate design policy applied to all other Edison customers but also with our decision in this proceeding to include streetlighting in our marginal cost revenue allocation process. The recommendations of PSD and CAL-SLA therefore mirror our effort to bring the design of streetlight rates into the "mainstream."

The value of a marginal cost-based approach to rate design and revenue allocation as a means of providing cost-based rates and accurate price signals has been repeated numerous times in this decision and is equally applicable to the streetlight customer. The fact that this approach might yield rates which are substantially less than that of another customer group of similar size should not lead to artificially imposing that schedule on streetlights. We agree with PSD and CAL-SLA that Edison's reliance on the TOU-GS schedule to calculate energy charges for streetlights is misplaced and is a significant departure from our polices emphasizing rates based on customer-imposed costs and use characteristics.

We therefore find reasonable PSD's proposed demand and energy charges for the street and area lighting customer group. These charges include the addition of 5% of the developed rate to the final rates to reflect miscellaneous costs identified by Edison. The further inclusion of the unallocated $2.5 million identified by Edison is therefore unnecessary.

4. Customer Charge

Edison states that, based on its cost of service study, it properly included a minimum distribution system charge to streetlight rates to reflect the hook-up cost of streetlight rates to allow an agricultural producer the opportunity to utilize cheaper off-peak electricity. By designing and substantiating a three-part schedule, PSD has provided an even greater opportunity for agricultural producers to lower their energy costs.

Indeed, we were disappointed in the area of agricultural rate design that there was not more active participation and information from the agricultural community itself during this proceeding. By law we cannot extend rates to any class unless those rates have been shown to be just and reasonable in the context of the individual class and the whole body of ratepayers. In this case, we believe that we have made substantial strides in implementing a responsive agricultural rate design. Because of lack of involvement by the agricultural ratepayers themselves, however, we are concerned with communicating the provisions and money-saving potential of these rates to agricultural ratepayers and assuring proper mitigation of detrimental impacts.

Consequently, we find that efforts must be made to reach out directly to this class of ratepayers and actively solicit input from this group. Edison is therefore directed to convene workshops, the purpose of which will be to explain the reasoning behind the new agricultural rate design and solicit input from ratepayers in this class on possible ways to "fine-tune" these rates. PSD (now called Division of Ratepayer Advocates) should also participate. We note that there will be no reallocation of revenues as a result of these workshops. We anticipate, however, that modification to the present rates will occur that will maximize the opportunity for agricultural ratepayers to lower their individual rates consistent with our philosophy of marginal cost pricing.

F. Street and Area Lighting Customer Group

1. Introduction

Several of the issues which have been raised with respect to streetlighting by Edison, PSD, and CAL-SLA have been previously customers. Edison further asserts that its customer charge for LS-3 metered service of $11.00 per meter per month, which was challenged by CAL-SLA, is reasonable and relies on the same methodology which Edison used in calculating the customer charges for series customers which were not opposed by CAL-SLA.

PSD disputes Edison's imposition of a MDS charge. PSD states that PSD's marginal customer cost approach (TSM) meets all of the criteria for establishing cost-based streetlighting rates and eliminates the necessity of an additional MDS charge.

CAL-SLA also disputes Edison imposition of an MDS charge. CAL-SLA states that no reason has been furnished by Edison to impose this charge in lieu of or in addition to PSD's TSM approach. CAL-SLA also recommends that customer charges be determined at a flat rate.

As this decision reflects, we have previously adopted PSD's TSM approach for determining marginal customer costs and have included in the revenue allocation process marginal customer costs for streetlighting developed on that basis. Having reflected marginal customer costs in revenues allocated to the streetlighting customer class, it is no longer necessary to include an MDS charge, as suggested by Edison, in streetlight rates. Edison's proposal is therefore rejected.

With respect to the determination of customer charges, we are concerned with CAL-SLA's suggestion that these charges be determined on a "flat rate" basis, when for other aspects of the streetlight rate structure CAL-SLA has supported marginal-cost based rates. In keeping with our adherence to marginal cost principles, we concur with PSD that the customer charges for this group should be based on the same methodology (marginal customer costs) applied to all other customer groups. We therefore adopt PSD's proposed customer charges for streetlighting.

addressed in this decision. These issues include our decision to include marginal customer costs and energy charges associated with streetlighting in the revenue allocation process. In this portion of our decision, we will focus on the specific recommendations made by Edison, PSD, and CAL-SLA with respect to the street and area lighting schedules LS-1 (Edison-owned street lamps), LS-2 (customer-owned street lamps), LS-3 (metered streetlight service), OL-1 (outdoor lighting), and DWL (domestic walkway).

Before we consider those issues, we note that PSD has expressed concern regarding the amount of time and effort devoted to streetlighting issues when only one characteristic distinguishes this class from other customer groups. That characteristic, according to PSD, is that certain customers in the streetlighting class rent their streetlights from Edison. PSD believes that this characteristic does not justify a totally different rate design approach than that applied to other customer groups. PSD asserts that the same basic, sound economic principles which guide the rate structures of other schedules should therefore be applied to the rate design adopted for streetlighting.

With this last statement, we agree. While the usage characteristics and other unique features of streetlighting customers should be considered in rate design, recognition of those characteristics do not require a wholesale departure from our adopted rate design philosophy. We believe that these customers can benefit from and should be charged rates which reflect the costs which these customers impose on the utility system. Our inclusion of streetlighting, with respect to the energy component of streetlight charges, and streetlighting marginal customer costs in the revenue allocation process are a recognition that these customers, despite unique traits, also share characteristics common to all other Edison customers.

As a frame of reference for our analysis of the various streetlighting issues, we also wish to note that in Edison's last

5. Facilities Charges

Both Edison and PSD have concluded that the appropriate methodology for calculating streetlight facilities charges is a Reproduction Cost New with an Economic Carrying Charge analysis. In contrast, CAL-SLA believes these charges should be based on Original Cost Less Depreciation to set the revenue requirement and Reproduction Cost New Less Depreciation for revenue allocation.

PSD and Edison have proposed almost identical facilities charges for streetlighting, except for PSD counting part of the Regulating Output or "RO" transformer as a facilities charge, an approach which we have previously adopted. Both parties have also agreed on a charge of $1.00 per lamp per year for the transformer charge on Edison-owned lamps.

PSD and Edison advocate pricing streetlight facilities based on a marginal cost approach. PSD states that this approach provides the proper price signals and approximates the long-run rental cost of providing streetlighting facilities to customers. PSD challenges CAL-SLA's approach which it states is not based on marginal costs and would not provide the proper price signals.

PSD also notes that its facilities charges were not scaled upwards to reflect their contribution to overall revenue requirement, as Edison has claimed. Rather, according to PSD, the facilities charges proposed by both itself and Edison are priced at full marginal cost.

We find that PSD and Edison have followed the correct approach to calculating streetlight facilities charges -- one based on the cost of those facilities at the margin. The parties have also appropriately used a Reproduction Cost New approach. This approach, consistent with that used by Edison in developing its cost of service study, provides a reasonable basis upon which to develop the facilities charge. Edison has made clear that its accounts do not include an OCLD figure for streetlights and has correctly stated that the Commission has permitted Edison to rely general rate case (D.84-12-068), we directed Edison for this proceeding to undertake a current cost of service study for streetlighting. Additionally, Edison was to provide alternative rate designs for streetlighting reflecting the "additive" and the "unbundled" approaches. The "additive" approach to rate design essentially requires each of the cost components of the total rate for the streetlight schedules to be identified. With these tools, the Commission concluded that revisions to the streetlighting schedules could be undertaken. We note that in this proceeding Edison has responded to both of these orders which are in keeping with our goal of providing cost-based, unbundled rates.

2. <u>Cost of Service Study</u>

CAL-SLA asserts that Edison's cost of service study for streetlighting fails to comply with D.86-12-068. CAL-SLA believes that Edison has interpreted the Commission's mandate to perform a historical cost analysis as permission to undertake a Reproduction Costs New analysis. CAL-SLA asserts that the proper approach would have been to reflect an Original Cost Less Depreciation (OCLD) analysis.

Edison objects to CAL-SLA's criticism of its cost study as unfounded. Edison states that it in fact performed its study the only way possible with the data currently available. Additionally, Edison cites page 370 of D.84-12-068 as requiring that the cost of service study for the streetlighting customer class be based on historical costs, if adequate records were available, <u>or</u> "build up" costs.

Edison states that its asset accounts, in keeping with the FERC Uniform System of Accounts, include none that are exclusively for streetlights and do not contain any reserve for depreciation as implied by CAL-SLA. Edison also notes that a OCLD figure is not readily available to Edison.

We find that Edison's cost of service study is in keeping with our directives in D.84-12-068. A Replacement Cost New on "build up" costs in the absence of reliable historical data. Edison has shown that an embedded cost of service study would be an expensive undertaking which would necessarily be borne by the streetlight customers.

We find no necessity of imposing such additional costs on these customers when the approach used by Edison in developing its cost of service study and by Edison and PSD in developing facilities charges is reasonable and should serve as the basis upon which to determine streetlight facilities charges. We therefore adopt PSD's facilities charges, which reflect our approval of the partial inclusion of the RO transformer in those charges.

6. Streetlight Rate Design

As stated previously, Edison responded in this proceeding to the Commission's directive in D.84-12-068 to provide alternative rate designs for streetlighting based on the "additive" and "unbundled" approaches. Edison states that its rate design is therefore based on the "unbundled" method where individual cost components were identified and aggregated to a total rate (an "additive" rate form). According to Edison, this rate structure uses a marginal cost-based rate design, recognizes marginal customer costs, and sends appropriate price signals to customers. In order to simplify the streetlighting tariffs and promote customer understanding, Edison has incorporated the existing Schedule LS-4 into the rate structure of Schedules LS-2 and LS-3, thereby eliminating the LS-4 schedule. Schedules LS-2 has also been revised to allow easier comparison to Schedule LS-1.

Despite this showing, CAL-SLA claims that Edison has failed to provide unbundled charges in its tariff sheets that are easily understood. CAL-SLA states that a review of Edison's tariff sheets reveals that charges are not listed as energy, customer, maintenance, and facilities, as CAL-SLA has consistently proposed. Unless the charges are separated as in this manner, CAL-SLA states that streetlight customers will not be able to determine which methodology was an appropriate basis on which to develop that study.

3. Energy and Demand Charges

In this proceeding, Edison states that it has responded to the directives of D.84-12-068 by proposing rate levels and rate design for streetlighting based on a cost of service analysis and reliance on both the additive and unbundled rate design approaches. Edison believes that the development by PSD and CAL-SLA of energy and demand rates for streetlights based on an EPMC allocation is contrary to the Commission's directives in D.84-12-068 which excluded streetlighting from the marginal cost revenue allocation process.

In calculating energy and demand charges for streetlights, Edison states that it based these rates on a weighted average TOU-GS rate. In addition to the weighted average TOU-GS rate, $2,500,000 of unallocated costs were spread on an equal-cents-per kWh basis for all street and area lighting customers. Edison states that its reliance of the TOU-GS rate is based on the reasoning that, if streetlight rates were eliminated, the streetlight customer would most likely be served under a general service tariff along with other customers of similar size and load shapes. According to Edison, the TOU-GS schedule seemed to be the most likely general service tariff under which streetlighting customers would be served under these circumstances due to the primarily off-peak usage of streetlights.

Edison questions the results of the PSD and CAL-SLA proposals which cut existing energy rates in half for all customers in the streetlight group in the face of rate increases to all other classes. Edison believes that there should be some relationship between the rates charged for streetlighting and those charged others for similar service (i.e., TOU-GS).

As noted by Edison, PSD and CAL-SLA advocate establishing energy charges for streetlighting on an EPMC basis. PSD recommends schedule to choose. CAL-SLA therefore requests that the Commission order Edison to prepare tariff sheets which provide for a clear distinction between energy, customer, maintenance, and facilities charges based upon a common denominator (i.e., per lamp per month basis).

In contrast, PSD states that it has reviewed and accepted Edison's "unbundled" rate design and "additive" rate form which it finds consistent with and directly responsive to Ordering Paragraph 11 of D.84-12-068. PSD states that offering a completely "unbundled" rate structure as proposed by CAL-SLA would be difficult to administer.

Edison also disputes CAL-SLA's assertion that its tariff sheets provide no division of major cost components. Edison believes that CAL-SLA has failed to recognize the distinction between unbundled charges for rate design and the information which is provided on a tariff sheet.

Edison states that its tariffs clearly identify the following charges: energy, series service power factor, relamping, and facilities and maintenance charges. The "other charges" to which CAL-SLA refers are, according to Edison, fixed facilities and their related maintenance and customer billing charges. Edison states that since a customer never maintains Edison facilities, it is not necessary to show the maintenance separate from the facility charge. Further, if a customer wants to examine the fully unbundled costs of streetlights, Edison states that it will provide the customer work sheets which in detail show all cost components. Edison notes that if it were to provide fully unbundled tariffs there would be thirty times more information required in its tariff sheets, a result which Edison states would hardly promote customer understanding.

We concur with Edison and PSD that Edison has complied with our order in D.84-12-068 in developing its rate structure for streetlighting. A review of Edison's tariffs reveals that these that an additional 5% of the developed rate be added to reflect miscellaneous streetlight costs identified by Edison. PSD believes that the EPMC approach which it advocates provides the proper price signals for streetlight customers and ensures uniformity in the rate design principles applied to all of Edison's customers.

PSD believes that Edison's reliance on the TOU-GS schedule as the basis for its streetlighting rate is unjustified. Edison's arguments regarding the size similarities between the streetlight and TOU-GS customer are, according to PSD, invalid. PSD asserts that the only specific link found by Edison between these two types of customers was that the average size of a streetlight customer was around 300 lamps. PSD states that the fallacy of Edison's logic can be seen in assuming that a customer with 3,000 streetlights would be analogous to a TOU-8 customer, while one with 10 streetlights would be analogous to a domestic customer.

PSD asserts that in fact Edison has provided no basis for asserting that the costs imposed on its system by a streetlight customer bear any relation to those imposed by a TOU-GS customer. Further, PSD states that there is absolutely no similarity between the load profile of these two customer types. The determination of load profile requires, in PSD's opinion, an examination of the profile of the entire class which for TOU-GS would include extensive on-peak usage that is absent from the load profile of streetlight customers. For the streetlight customer, PSD cites the testimony of Edison's own witness that streetlights are characterized "by a uniform load curve, the bulk of which is in the off-peak and mid-peak areas with a small portion in the on-peak area." (Tr. at p. 4019.)

CAL-SLA concurs with PSD's assertion that the evidence does not support Edison's proposed energy charge. Like PSD, CAL-SLA questions Edison's reliance on a schedule (TOU-GS) which includes customers whose load in no way reflects the usage tariffs do reflect "unbundled" rates. The level of detail requested by CAL-SLA was not intended by our last order, and we question, like Edison, whether such detail would in fact heighten customer understanding. Given the amount of time and expense which would no doubt be required to develop and explain such a tariff, we do not believe that such costs are justified or that the streetlight class would significantly benefit from those changes.

We therefore find reasonable and adopt Edison's proposed rate design for streetlighting. For Edison's next general rate case, Edison should, however, consider what detail could be added to the tariff which would enhance customer understanding.

7. Rate Limiter

CAL-SLA states that for many lamp-types, Edison's rate proposal results in significant rate increases over present levels. CAL-SLA states that any such rate increase is unfair given Edison's requested increase in revenue of 5.3% as compared to the increases for certain lamp type which will range from 12% to 91% per lamp. CAL-SLA therefore recommends that a 5% cap be placed on any rate increase for streetlighting with no cap being placed on rate decreases.

For streetlight rates, Edison states that it has no objection in concept to a rate cap provided that cap is functional, fair to all customers, and applicable to both rate increases and decreases. Edison notes, however, that while individual lamps may have increases up to 130% or decreases up to 50%, any given customer may have no net change or very little change based on the customers' mix of lamps.

PSD disputes the need for rate limiters for streetlighting rates. Like Edison, PSD states that for most streetlight customers, little or no net change in rates will be experienced based on the customer's mix of lamps.

For the large power customer group, we have adopted rate limiters on-peak period charges designed to mitigate adverse rate characteristics of the streetlight customer group. If TOU-GS is to be used, CAL-SLA questions why the TOU-GS-SOP (super off peak) rate was not selected since such a rate schedule would be more consistent with the usage patterns of a streetlight customer.

CAL-SLA also questions Edison's proposal to allocate $2.5 million on an equal cents per kilowatt-hour basis to the streetlight class as a whole and not to the specific schedules to which these costs can be attributed. CAL-SLA further asserts that Edison has failed to present the complete factual data necessary for a showing to justify the inclusion of these unallocated charges in rates.

We concur with PSD's and CAL-SLA's recommendation that streetlight energy and demand charges should be based on marginal costs. This approach is consistent not only with the rate design policy applied to all other Edison customers but also with our decision in this proceeding to include streetlighting in our marginal cost revenue allocation process. The recommendations of PSD and CAL-SLA therefore mirror our effort to bring the design of streetlight rates into the "mainstream."

The value of a marginal cost-based approach to rate design and revenue allocation as a means of providing cost-based rates and accurate price signals has been repeated numerous times in this decision and is equally applicable to the streetlight customer. The fact that this approach might yield rates which are substantially less than that of another customer group of similar size should not lead to artificially imposing that schedule on streetlights. We agree with PSD and CAL-SLA that Edison's reliance on the TOU-GS schedule to calculate energy charges for streetlights is misplaced and is a significant departure from our polices emphasizing rates based on customer-imposed costs and use characteristics.

We therefore find reasonable PSD's proposed demand and energy charges for the street and area lighting customer group.

impacts resulting from our adopted rate structures for the TOU-8 and standby rate schedules. In the case of streetlights, usage is almost entirely off-peak permitting these customers to take advantage of lower rates in the first place. The unique usage characteristics of streetlight customers, in this instance, therefore, does not require that a mechanism designed for customers faced with substantially different circumstances be extended to the streetlight class. We also find that the record reflects that the customer's mix of lamps will largely offset that customer being faced with any of the significant increases attributable to one particular lamp type. For these reasons, we reject CAL-SLA's request for a rate limiter on streetlight rates.

8. Miscellaneous Issues

Edison, PSD, and CAL-SLA agreed on a number of miscellaneous issues. Among them PSD and CAL-SLA agreed on (1) the load shape used by Edison in determining the time-of-use characteristics of this class, (2) the refined series kWh losses calculated by Edison for use in calculating energy consumption for LS-2 series customers, (3) the series KVAR losses calculated by Edison and the "Series Service Power Factor Charge" of $0.30 per kVAR demand, and (4) the weighted average pole charge developed by Edison for inclusion in the LS-1 lamp-related charges. We find that these proposed charges and rate structures are reasonable and should be adopted.

In the following sections, we will review issues which remain in dispute. These issues were principally addressed by CAL-SLA and Edison.

a. Customer Account Expense

Edison and PSD have agreed to a customer account expense of $.12058 per lamp per month. CAL-SLA has proposed a charge of $0.22 per lamp per month based on Edison's average cost study.

In designing its rates for streetlighting, Edison states that it has developed all charges on a marginal cost basis. Edison

These charges include the addition of 5% of the developed rate to the final rates to reflect miscellaneous costs identified by Edison. The further inclusion of the unallocated $2.5 million identified by Edison is therefore unnecessary.

4. Customer Charge

Edison states that, based on its cost of service study, it properly included a minimum distribution system charge to streetlight rates to reflect the hook-up cost of streetlight customers. Edison further asserts that its customer charge for LS-3 metered service of $11.00 per meter per month, which was challenged by CAL-SLA, is reasonable and relies on the same methodology which Edison used in calculating the customer charges for series customers which were not opposed by CAL-SLA.

PSD disputes Edison's imposition of a MDS charge. PSD states that PSD's marginal customer cost approach (TSM) meets all of the criteria for establishing cost-based streetlighting rates and eliminates the necessity of an additional MDS charge.

CAL-SLA also disputes Edison imposition of an MDS charge. CAL-SLA states that no reason has been furnished by Edison to impose this charge in lieu of or in addition to PSD's TSM approach. CAL-SLA also recommends that customer charges be determined at a flat rate.

As this decision reflects, we have previously adopted PSD's TSM approach for determining marginal customer costs and have included in the revenue allocation process marginal customer costs for streetlighting developed on that basis. Having reflected marginal customer costs in revenues allocated to the streetlighting customer class, it is no longer necessary to include an MDS charge, as suggested by Edison, in streetlight rates. Edison's proposal is therefore rejected.

With respect to the determination of customer charges, we are concerned with CAL-SLA's suggestion that these charges be determined on a "flat rate" basis, when for other aspects of the therefore disputes CAL-SLA's reliance on Edison's average cost study which would improperly mix the results of that study with a marginal cost-based rate design.

We concur with Edison that, for consistency in the methodology used to calculate structure rates, it is appropriate to rely on marginal costs to develop the customer account expense. We therefore find reasonable and adopt a customer account expense of $0.12058 per lamp per month as Edison and PSD have agreed.

b. Domestic Walkway Lighting (DWL) Rates

CAL-SLA has questioned Edison's proposed cable and photocontroller charge for customer-owned systems on Schedule DWL. Edison states that since CAL-SLA proposes no alternate rate or solution, their simple lack of understanding of the rate negotiated on special contracts is not sufficient to eliminate the charge. We concur with Edison and will adopt its proposed cable and photocontroller charges for the DWL schedule.

c. Proposed Special Conditions

CAL-SLA asserts that Edison's proposed Special Condition 2 relating to the installation of LS-2 and LS-3 streetlights does not reflect present circumstances. CAL-SLA has therefore proposed its own version of Special Condition 2. According to CAL-SLA, its proposal is consistent with the current arrangement of installing LS-2 and LS-3 streetlights with the locations decided on a case-by-case basis between local government, land developer, and the utility.

We find that CAL-SLA has justified its proposed change to Special Condition 2, contrary to Edison's statements that no reason was offered for that change. In keeping with current installation practices, Special Condition 2 should therefore reflect the language proposed by CAL-SLA.

CAL-SLA additionally recommends that Edison's proposed Special Condition 10 of Schedule LS-2 relating to kilowatt-hours be amended to reflect the lamp loads and kWh estimates for HPSV and streetlight rate structure CAL-SLA has supported marginal-cost based rates. In keeping with our adherence to marginal cost principles, we concur with PSD that the customer charges for this group should be based on the same methodology (marginal customer costs) applied to all other customer groups. We therefore adopt PSD's proposed customer charges for streetlighting.

5. Facilities Charges

Both Edison and PSD have concluded that the appropriate methodology for calculating streetlight facilities charges is a Reproduction Cost New with an Economic Carrying Charge analysis. In contrast, CAL-SLA believes these charges should be based on Original Cost Less Depreciation to set the revenue requirement and Reproduction Cost New Less Depreciation for revenue allocation.

PSD and Edison have proposed almost identical facilities charges for streetlighting, except for PSD counting part of the Regulating Output or "RO" transformer as a facilities charge, an approach which we have previously adopted. Both parties have also agreed on a charge of $1.00 per lamp per year for the transformer charge on Edison-owned lamps.

PSD and Edison advocate pricing streetlight facilities based on a marginal cost approach. PSD states that this approach provides the proper price signals and approximates the long-run rental cost of providing streetlighting facilities to customers. PSD challenges CAL-SLA's approach which it states is not based on marginal costs and would not provide the proper price signals.

PSD also notes that its facilities charges were not scaled upwards to reflect their contribution to overall revenue requirement, as Edison has claimed. Rather, according to PSD, the facilities charges proposed by both itself and Edison are priced at full marginal cost.

We find that PSD and Edison have followed the correct approach to calculating streetlight facilities charges -- one based on the cost of those facilities at the margin. The parties have

LPSV lamps recommended by CAL-SLA. CAL-SLA notes that for PG&E the Commission agreed with CAL-SLA that the manufacturer's specifications should be used for determining energy usage of streetlights (D.86-12-091, at pages 90-91). In that proceeding, CAL-SLA notes that the Commission specifically rejected PG&E's contention that the manufacturer's specifications should be modified to include a 3% line loss factor.

CAL-SLA states that its review of manufacturer's specifications for lamp loads does not show a 3% loss. CAL-SLA therefore recommends that Special Condition 12 of proposed Schedule LS-2 be amended to exclude the alleged 3% line loss factor.

Edison states that in making these recommendations, CAL-SLA has ignored actual field operations affecting energy consumption and incorrectly characterizes the existing conditions. Edison asserts that the 3% is not a line loss, but a confirmed operational loss factor from the operation of a lamp in field conditions. CAL-SLA, in Edison's opinion, has also not provided any evidence to support its proposal that Edison's lamp loads should be other than authorized and based on manufacturer specifications which ignore these field conditions.

We are concerned that Edison's reliance on previously authorized lamp loads, as PG&E had, may also not reflect current manufacturers specifications or conditions. We believe that CAL-SLA has presented sufficient justification for our reliance on those specifications even if they do not completely reflect actual field operations. This reliance requires our adoption of the modifications proposed by CAL-SLA for Special Conditions 10 and 12 of the LS-2 schedule.

d. Ownership of Photocells and Related Facilities and Regulated Output Transformers

CAL-SLA recommends that Special Condition 3 of Schedule LS-2 relating to "Switching and Related Facilities" be removed from the tariff schedule. According to CAL-SLA, "switching" refers also appropriately used a Reproduction Cost New approach. This approach, consistent with that used by Edison in developing its cost of service study, provides a reasonable basis upon which to develop the facilities charge. Edison has made clear that its accounts do not include an OCLD figure for streetlights and has correctly stated that the Commission has permitted Edison to rely on "build up" costs in the absence of reliable historical data. Edison has shown that an embedded cost of service study would be an expensive undertaking which would necessarily be borne by the streetlight customers.

We find no necessity of imposing such additional costs on these customers when the approach used by Edison in developing its cost of service study and by Edison and PSD in developing facilities charges is reasonable and should serve as the basis upon which to determine streetlight facilities charges. We therefore adopt PSD's facilities charges, which reflect our approval of the partial inclusion of the RO transformer in those charges.

6. <u>Streetlight Rate Design</u>

As stated previously, Edison responded in this proceeding to the Commission's directive in D.84-12-068 to provide alternative rate designs for streetlighting based on the "additive" and "unbundled" approaches. Edison states that its rate design is therefore based on the "unbundled" method where individual cost components were identified and aggregated to a total rate (an "additive" rate form). According to Edison, this rate structure uses a marginal cost-based rate design, recognizes marginal customer costs, and sends appropriate price signals to customers. In order to simplify the streetlighting tariffs and promote customer understanding, Edison has incorporated the existing Schedule LS-4 into the rate structure of Schedules LS-2 and LS-3, thereby eliminating the LS-4 schedule. Schedules LS-2 has also been revised to allow easier comparison to Schedule LS-1.

to an obsolete arrangement under which the streetlight circuit is switched on and off. CAL-SLA states that the current, typical arrangement is to have a photoelectric cell control a streetlight.

CAL-SLA states that, based on its own survey, six of the nine streetlight customers contacted indicated that they owned and maintained the photocells which are part of the otherwise customer-owned pedestal. Under these circumstances, CAL-SLA believes that the retention of Special Condition 3 is unnecessary and its removal would reflect that the customer owns and maintains the photocell. CAL-SLA notes that neither PG&E nor SDG&E have a condition similar to Special Condition 3 nor do these utilities claim they own and maintain the photocells in customer-owned luminaries.

Edison states that CAL-SLA's proposal does not relate to rate design, but rather to customer compliance with existing authorized tariffs. Edison asserts that these tariffs which clearly state Edison's ownership of streetlight switching equipment (i.e., the photocell) are not altered by the customer's belief in his ownership of that equipment. Edison states that the solution to this problem is not to change the tariff to accommodate a minority of customers who are in violation of the terms of the tariff, but to bring those customers into compliance with the tariff. Edison analogizes customers' claims of ownership of the photocell, which is locked and sealed in a separate section of the service pedestal along with any applicable meters, timeblocks or relays, to a residential customer claiming to own the service meter simply because it is attached to its residence.

We similarly find that a review of CAL-SLA's testimony and argument reflects that its study merely revealed what the streetlight customers "believed" and not what was in fact the case. While we certainly agree that the customer could be responsible for maintaining a photocell, the fact that ownership apparently resides in Edison does not guarantee that such maintenance would take place. We therefore find it more prudent for the protection of

Despite this showing, CAL-SLA claims that Edison has failed to provide unbundled charges in its tariff sheets that are easily understood. CAL-SLA states that a review of Edison's tariff sheets reveals that charges are not listed as energy, customer, maintenance, and facilities, as CAL-SLA has consistently proposed. Unless the charges are separated as in this manner, CAL-SLA states that streetlight customers will not be able to determine which schedule to choose. CAL-SLA therefore requests that the Commission order Edison to prepare tariff sheets which provide for a clear distinction between energy, customer, maintenance, and facilities charges based upon a common denominator (i.e., per lamp per month basis).

In contrast, PSD states that it has reviewed and accepted Edison's "unbundled" rate design and "additive" rate form which it finds consistent with and directly responsive to Ordering Paragraph 11 of D.84-12-068. PSD states that offering a completely "unbundled" rate structure as proposed by CAL-SLA would be difficult to administer.

Edison also disputes CAL-SLA's assertion that its tariff sheets provide no division of major cost components. Edison believes that CAL-SLA has failed to recognize the distinction between unbundled charges for rate design and the information which is provided on a tariff sheet.

Edison states that its tariffs clearly identify the following charges: energy, series service power factor, relamping, and facilities and maintenance charges. The "other charges" to which CAL-SLA refers are, according to Edison, fixed facilities and their related maintenance and customer billing charges. Edison states that since a customer never maintains Edison facilities, it is not necessary to show the maintenance separate from the facility charge. Further, if a customer wants to examine the fully unbundled costs of streetlights, Edison states that it will provide the customer work sheets which in detail show all cost components.

those streetlight customers who rent streetlights from Edison, for which equipment Edison is ultimately responsible, to maintain the current special condition to ensure continuous streetlighting.

G. Optional Time-Of-Use Meter Charges

Edison has proposed monthly meter charges for its proposed optional TOU schedules in addition to the proposed monthly customer charges. The proposed meter charges are set to cover the differential in metering costs between a conventional meter and a time-of-use meter.

Edison has not included the costs associated with its option meter plan in its results of operation showing. To ensure the appropriate recovery of revenue, we will therefore reflect the following estimated costs for time-of-use meters in our adopted results of operation: $369,500 in 1988; $1,012,600 in 1989; and $1,559,800 in 1990.

H. Rate Design Between General Rate Case Proceedings

Edison and PSD disagree on how to adjust the various rate components as a result of revenue requirement changes occurring between general rate cases. Edison proposes to hold demand and customer charges constant between general rate cases and make all adjustments in the energy charges. In contrast, PSD proposes to increase demand and customer charges toward their EPMC relationships for revenue requirement increases, but to hold them constant for decreases.

Edison states that its concerns with PSD's approach are not only with the mechanics of calculating the adjustments, but also with the fact that that the attainment of full EPMC rates is not desirable for all rate components. Edison is particularly concerned that total reliance on EPMC will result in creating severe bill impacts and tilting of rates to an extent that would induce uneconomic bypass. Edison believes that its proposal strikes a balance between theoretical and practical considerations in the design of demand rates.

Edison notes that if it were to provide fully unbundled tariffs there would be thirty times more information required in its tariff sheets, a result which Edison states would hardly promote customer understanding.

We concur with Edison and PSD that Edison has complied with our order in D.84-12-068 in developing its rate structure for streetlighting. A review of Edison's tariffs reveals that these tariffs do reflect "unbundled" rates. The level of detail requested by CAL-SLA was not intended by our last order, and we question, like Edison, whether such detail would in fact heighten customer understanding. Given the amount of time and expense which would no doubt be required to develop and explain such a tariff, we do not believe that such costs are justified or that the streetlight class would significantly benefit from those changes.

We therefore find reasonable and adopt Edison's proposed rate design for streetlighting. For Edison's next general rate case, Edison should, however, consider what detail could be added to the tariff which would enhance customer understanding.

7. Rate Limiter

CAL-SLA states that for many lamp-types, Edison's rate proposal results in significant rate increases over present levels. CAL-SLA states that any such rate increase is unfair given Edison's requested increase in revenue of 5.3% as compared to the increases for certain lamp type which will range from 12% to 91% per lamp. CAL-SLA therefore recommends that a 5% cap be placed on any rate increase for streetlighting with no cap being placed on rate decreases.

For streetlight rates, Edison states that it has no objection in concept to a rate cap provided that cap is functional, fair to all customers, and applicable to both rate increases and decreases. Edison notes, however, that while individual lamps may have increases up to 130% or decreases up to 50%, any given

PSD asserts, however, that reliance on Edison's approach may leave demand and customer charges even further from their EPMC relationships than they are today, particularly if Edison's revenue requirement increases. PSD states that its approach ensures that steady progress toward EPMC will be made and makes any back-slide impossible.

With our adoption of rate limiters and other rate design features designed to moderate adverse bill impacts, we do not believe PSD's approach to rate design for intervening rate increases will result in any unwarranted rate impacts which might, independent of all other considerations, further uneconomic bypass. We also believe that PSD's proposal is consistent with our adherence to marginal cost principles for revenue allocation and rate design. The problems encountered in this proceeding which required revenue allocation and rate design caps were created by revenues having been allocated and rates having been designed on concepts other than marginal costs in past years. It is not our intention to retard this process of achieving cost-based rates any further by adopting a means of adjusting rates in the interim which could lead to further separation between rates and marginal costs.

We therefore find reasonable and adopt PSD's proposal to increase demand and customer charges toward their EPMC relationships for revenue requirement increases, but to hold them constant for decreases. Revenue changes between general rate case properly attributable to energy charges, however, should be reflected in that rate component.

customer may have no net change or very little change based on the customers' mix of lamps.

PSD disputes the need for rate limiters for streetlighting rates. Like Edison, PSD states that for most streetlight customers, little or no net change in rates will be experienced based on the customer's mix of lamps.

For the large power customer group, we have adopted rate limiters on-peak period charges designed to mitigate adverse rate impacts resulting from our adopted rate structures for the TOU-8 and standby rate schedules. In the case of streetlights, usage is almost entirely off-peak permitting these customers to take advantage of lower rates in the first place. The unique usage characteristics of streetlight customers, in this instance, therefore, does not require that a mechanism designed for customers faced with substantially different circumstances be extended to the streetlight class. We also find that the record reflects that the customer's mix of lamps will largely offset that customer being faced with any of the significant increases attributable to one particular lamp type. For these reasons, we reject CAL-SLA's request for a rate limiter on streetlight rates.

8. <u>Miscellaneous Issues</u>

Edison, PSD, and CAL-SLA agreed on a number of miscellaneous issues. Among them PSD and CAL-SLA agreed on (1) the load shape used by Edison in determining the time-of-use characteristics of this class, (2) the refined series kWh losses calculated by Edison for use in calculating energy consumption for LS-2 series customers, (3) the series KVAR losses calculated by Edison and the "Series Service Power Factor Charge" of $0.30 per kVAR demand, and (4) the weighted average pole charge developed by Edison for inclusion in the LS-1 lamp-related charges. We find that these proposed charges and rate structures are reasonable and should be adopted.

Findings of Fact

1. On December 26, 1986 Edison filed A.86-12-047 requesting: (1) authority to increase base rate revenues by $301.5 million or 5.4% for test year 1988, and (2) attrition increases for 1989 and 1990.

2. I.87-01-017 was issued and consolidated with A.86-12-047 on January 14, 1987 to consider a reduction in Edison's rates.

3. Edison's revised request increases base rate revenues by $79.0 million or 1.4%.

4. Six days of public hearings, including a Commission en banc public hearing, were held during April 1986.

5. The Administrative Law Judge's draft decision was issued on November 20, 1987.

6. Edison and PSD have agreed to a labor escalation rate of 3.5% for both 1987 and 1988.

7. Edison and PSD have agreed to the methodology for developing non-labor escalation rates and recommend rates of 2.99% for 1987 and 4.41% for 1988.

8. Edison and PSD are in agreement with respect to the forecast of kilowatt-hour sales as shown in the table Summary of Kilowatt-Hour Sales on page 6 of this decision.

9. With the exception of other operating revenues Edison and PSD have agreed to present rate revenues which include $19.4 million in CLMAC revenues.

10. Present CLMAC rates were established to recover expenses associated with conservation and load management programs incurred prior to test year 1988.

11. Edison proposes to increase accounts 512 and 513 by over 50% due to the development of new criteria for scheduling steam generating unit overhauls.

12. Edison expects the new overhaul criteria to reduce routine activities, but failed to quantify this benefit.

In the following sections, we will review issues which remain in dispute. These issues were principally addressed by CAL-SLA and Edison.

a. Customer Account Expense

Edison and PSD have agreed to a customer account expense of $.12058 per lamp per month. CAL-SLA has proposed a charge of $0.22 per lamp per month based on Edison's average cost study.

In designing its rates for streetlighting, Edison states that it has developed all charges on a marginal cost basis. Edison therefore disputes CAL-SLA's reliance on Edison's average cost study which would improperly mix the results of that study with a marginal cost-based rate design.

We concur with Edison that, for consistency in the methodology used to calculate structure rates, it is appropriate to rely on marginal costs to develop the customer account expense. We therefore find reasonable and adopt a customer account expense of $0.12058 per lamp per month as Edison and PSD have agreed.

b. Domestic Walkway Lighting (DWL) Rates

CAL-SLA has questioned Edison's proposed cable and photocontroller charge for customer-owned systems on Schedule DWL. Edison states that since CAL-SLA proposes no alternate rate or solution, their simple lack of understanding of the rate negotiated on special contracts is not sufficient to eliminate the charge. We concur with Edison and will adopt its proposed cable and photocontroller charges for the DWL schedule.

c. Proposed Special Conditions

CAL-SLA asserts that Edison's proposed Special Condition 2 relating to the installation of LS-2 and LS-3 streetlights does not reflect present circumstances. CAL-SLA has therefore proposed its own version of Special Condition 2. According to CAL-SLA, its proposal is consistent with the current arrangement of installing

13. Repairs planned for the low pressure turbine rotor at Redondo generating station unit 7 are not performed on a routine annual basis.

14. Edison and PSD recommend that $20.5 million be adopted for test year hydro production expense.

15. Edison and PSD recommend that $17.2 million be adopted for test year other production expense.

16. Edison and PSD are in agreement with respect to the test year level of production expense for SONGS.

17. Edison and PSD are in agreement that it is appropriate to consider an increase in NRC fees during the test year through the attrition mechanism.

18. Edison, PSD, and FEA are in agreement with the continuation of the flexible refueling mechanism adopted in Edison's last general rate case for use with SONGS and Palo Verde refuelings.

19. For Palo Verde O&M expenses Edison utilized ANPP's zero-based estimate prepared by ANPP managers and supervisors with Edison as a participant.

20. Without changing ANPP's total O&M expense estimate, Edison scaled-up the Palo Verde refueling outage expense to reflect actual experience at SONGS 2 and 3. This resulted in a reduction in ANPP's budgeted O&M expense estimate of $1.2 million.

21. Because of an absence of operating history at Palo Verde, PSD recommends that the O&M expenses for these units be determined from the 1985 average O&M expenses for 24 large nuclear units.

22. The comparative study used by PSD does not consider differences among nuclear plants, shows O&M expenses varied by $20 million above or below the average, reflects an increase in 1986 expenses of 11.8%, and does not exclude refueling expenses.

23. The chemical cleaning process that will be performed in conjunction with the replacement of the feedwater heaters is a one-time expense for SONGS 3.

LS-2 and LS-3 streetlights with the locations decided on a case-by-case basis between local government, land developer, and the utility.

We find that CAL-SLA has justified its proposed change to Special Condition 2, contrary to Edison's statements that no reason was offered for that change. In keeping with current installation practices, Special Condition 2 should therefore reflect the language proposed by CAL-SLA.

CAL-SLA additionally recommends that Edison's proposed Special Condition 10 of Schedule LS-2 relating to kilowatt-hours be amended to reflect the lamp loads and kWh estimates for HPSV and LPSV lamps recommended by CAL-SLA. CAL-SLA notes that for PG&E the Commission agreed with CAL-SLA that the manufacturer's specifications should be used for determining energy usage of streetlights (D.86-12-091, at pages 90-91). In that proceeding, CAL-SLA notes that the Commission specifically rejected PG&E's contention that the manufacturer's specifications should be modified to include a 3% line loss factor.

CAL-SLA states that its review of manufacturer's specifications for lamp loads does not show a 3% loss. CAL-SLA therefore recommends that Special Condition 12 of proposed Schedule LS-2 be amended to exclude the alleged 3% line loss factor.

Edison states that in making these recommendations, CAL-SLA has ignored actual field operations affecting energy consumption and incorrectly characterizes the existing conditions. Edison asserts that the 3% is not a line loss, but a confirmed operational loss factor from the operation of a lamp in field conditions. CAL-SLA, in Edison's opinion, has also not provided any evidence to support its proposal that Edison's lamp loads should be other than authorized and based on manufacturer specifications which ignore these field conditions.

We are concerned that Edison's reliance on previously authorized lamp loads, as PG&E had, may also not reflect current

24. Edison plans to perform a chemical cleaning process in the future on SONGS 2.

25. Edison requests recovery of $2.9 million for expenses previously incurred for the reprocessing of spent nuclear fuel from SONGS 1.

26. Edison did not receive prior approval for the expenses in finding 25 nor did it receive approval of a mechanism for tracking these costs for later recovery.

27. Edison and PSD recommend that $75.3 million be adopted for test year transmission expense.

28. Edison's estimate for account 582, station expenses, is based on 1985 recorded without adjusting for growth or productivity.

29. PSD's estimate for account 582 reflects recorded downward trends in labor expenses and as a result is $3.5 million lower than Edison's estimate.

30. Edison has replaced a number of its tree trimming crews with contract labor and reflects this in its estimate for account 583, overhead line expenses.

31. PSD's estimate for account 583 does not reflect Edison's transition to contract labor.

32. Expenses for account 597, maintenance of meters, were lower for the years 1982-1985 than for the years 1979-1981 because all purchases of meter locking rings were assigned to the energy theft program.

33. Unlike PSD, Edison reflected the accounting change for meter locking rings in its estimate for account 597.

34. Edison's underground switch failures have increased from 27.5 per year to 85.8 per year.

35. On April 1, 1987, Edison implemented a new three-year program for the inspection of its underground facilities including a laboratory analysis of the insulating oil in all transformers and switches.

manufacturers specifications or conditions. We believe that CAL-SLA has presented sufficient justification for our reliance on those specifications even if they do not completely reflect actual field operations. This reliance requires our adoption of the modifications proposed by CAL-SLA for Special Conditions 10 and 12 of the LS-2 schedule.

d. Ownership of Photocells and Related Facilities and Regulated Output Transformers

CAL-SLA recommends that Special Condition 3 of Schedule LS-2 relating to "Switching and Related Facilities" be removed from the tariff schedule. According to CAL-SLA, "switching" refers to an obsolete arrangement under which the streetlight circuit is switched on and off. CAL-SLA states that the current, typical arrangement is to have a photoelectric cell control a streetlight.

CAL-SLA states that, based on its own survey, six of the nine streetlight customers contacted indicated that they owned and maintained the photocells which are part of the otherwise customer-owned pedestal. Under these circumstances, CAL-SLA believes that the retention of Special Condition 3 is unnecessary and its removal would reflect that the customer owns and maintains the photocell. CAL-SLA notes that neither PG&E nor SDG&E have a condition similar to Special Condition 3 nor do these utilities claim they own and maintain the photocells in customer-owned luminaries.

Edison states that CAL-SLA's proposal does not relate to rate design, but rather to customer compliance with existing authorized tariffs. Edison asserts that these tariffs which clearly state Edison's ownership of streetlight switching equipment (i.e., the photocell) are not altered by the customer's belief in his ownership of that equipment. Edison states that the solution to this problem is not to change the tariff to accommodate a minority of customers who are in violation of the terms of the tariff, but to bring those customers into compliance with the tariff. Edison analogizes customers' claims of ownership of the

36. The increase in Edison's labor expense for the three-year underground inspection program comes from employees who were involved in new business construction. These employees will be replaced by contract crews.

37. PSD considers the increase in labor for the three-year underground inspection program to be double counting because the labor will be performed by existing employees.

38. PSD does not believe that the increase in underground equipment failures poses an immediate threat to Edison's underground distribution system and recommends against an increase in laboratory analysis.

39. A five-year average of account 598, storm damages, was adopted in Edison's last three general rate cases.

40. PSD recommends an eight-year average of account 598 be adopted to consider more years of a climatic cycle.

41. PSD has not presented evidence that more years of a climatic cycle will result in a more accurate estimate of storm damages.

42. Edison requests $4.3 million for posting termination notices on the customer's premises due to PU Section 779.1.

43. Edison has not provided the record with documentation of the study it performed from which it concluded that termination notices by telephone are not less costly than termination notices posted on the customer's premises.

44. PSD's estimated cost of providing termination notices to customers assumes that telephone notices are less costly than posting notices.

45. Edison's participation in Enercom produced savings of $225,000 in 1986 of which 10% was from former customers outside Edison's territory.

46. PSD estimates that Edison's participation in Enercom will yield savings of $775,000 in 1988 based on an increase in the number of participating utilities.

photocell, which is locked and sealed in a separate section of the service pedestal along with any applicable meters, timeblocks or relays, to a residential customer claiming to own the service meter simply because it is attached to its residence.

We similarly find that a review of CAL-SLA's testimony and argument reflects that its study merely revealed what the streetlight customers "believed" and not what was in fact the case. While we certainly agree that the customer could be responsible for maintaining a photocell, the fact that ownership apparently resides in Edison does not guarantee that such maintenance would take place. We therefore find it more prudent for the protection of those streetlight customers who rent streetlights from Edison, for which equipment Edison is ultimately responsible, to maintain the current special condition to ensure continuous streetlighting.

G. Optional Time-Of-Use Meter Charges

Edison has proposed monthly meter charges for its proposed optional TOU schedules in addition to the proposed monthly customer charges. The proposed meter charges are set to cover the differential in metering costs between a conventional meter and a time-of-use meter.

Edison has not included the costs associated with its optional meter plan in its results of operation showing. To ensure the appropriate recovery of revenue, we will therefore reflect the following estimated costs for time-of-use meters in our adopted results of operation: $369,500 in 1988; $1,012,600 in 1989; and $1,559,800 in 1990.

H. Rate Design Between General Rate Case Proceedings

Edison and PSD disagree on how to adjust the various rate components as a result of revenue requirement changes occurring between general rate cases. Edison proposes to hold demand and customer charges constant between general rate cases and make all adjustments in the energy charges. In contrast, PSD proposes to increase demand and customer charges toward their EPMC

47. PSD did not present evidence that there would be an increase in the number of utilities participating in Enercom in 1988.

48. Edison's benefits from Enercom exceed its costs by six to one.

49. Edison agrees with PSD's use of a three-year average of uncollectibles.

50. Increases during the test year for items minor in nature have not been authorized in the past.

51. A minor increase for postage is likely to occur during the test year.

52. A&G expenses can be separated into two categories: items over which Edison has control and items over which Edison does not have direct control.

53. Customer growth impacts A&G expenses.

54. Customer growth from 1985 to 1988 is expected to be 8 percent.

55. Pension, medical, dental, and vision plan costs, insurance, franchise taxes, and F/MBE program costs are items over which Edison does not have direct control.

56. Edison's recorded insurance premiums have generally followed market trends.

57. Recently insurance premiums have risen precipitously.

58. Some insurance professionals indicate a decline in insurance premiums.

59. Edison's estimate of insurance premiums does not reflect a softening in the insurance market.

60. Directors and officers insurance protects ratepayers and stockholders.

61. Edison and PSD have agreed to the estimated insurance premiums for crime, nuclear property, nuclear replacement generation, and nuclear liability.

relationships for revenue requirement increases, but to hold them constant for decreases.

Edison states that its concerns with PSD's approach are not only with the mechanics of calculating the adjustments, but also with the fact that that the attainment of full EPMC rates is not desirable for all rate components. Edison is particularly concerned that total reliance on EPMC will result in creating severe bill impacts and tilting of rates to an extent that would induce uneconomic bypass. Edison believes that its proposal strikes a balance between theoretical and practical considerations in the design of demand rates.

PSD asserts, however, that reliance on Edison's approach may leave demand and customer charges even further from their EPMC relationships than they are today, particularly if Edison's revenue requirement increases. PSD states that its approach ensures that steady progress toward EPMC will be made and makes any back-slide impossible.

With our adoption of rate limiters and other rate design features designed to moderate adverse bill impacts, we do not believe PSD's approach to rate design for intervening rate increases will result in any unwarranted rate impacts which might, independent of all other considerations, further uneconomic bypass. We also believe that PSD's proposal is consistent with our adherence to marginal cost principles for revenue allocation and rate design. The problems encountered in this proceeding which required revenue allocation and rate design caps were created by revenues having been allocated and rates having been designed on concepts other than marginal costs in past years. It is not our intention to retard this process of achieving cost-based rates any further by adopting a means of adjusting rates in the interim which could lead to further separation between rates and marginal costs. We therefore find reasonable and adopt PSD's proposal to increase demand and customer charges toward their EPMC

62. PSD reduced Edison's estimate of group life insurance because of insufficient documentation to justify Edison's request.

63. PSD's estimate of outside provider medical costs is based on the latest recorded data and assumes no growth in participants.

64. Edison's annual energy, ECAC, and MAAC rates are calculated using Edison's latest adopted franchise tax and uncollectible rates.

65. The Superfund Tax is a new tax which Edison and experts within the utility industry have interpreted as a deductible tax.

66. Edison and PSD have incorporated the provisions of the Federal Tax Reform Act of 1986 in their tax calculations.

67. Edison estimated 1988 plant-in-service by adding forecasted plant additions from its five-year plant and work element budget to 1985 recorded plant.

68. Edison and PSD have agreed to the depreciation rates to be used in calculating depreciation expense and reserve.

69. Edison and PSD have agreed to guidelines for evaluating PHFU in future proceedings.

70. Edison has agreed to reduce its PHFU estimate by $7.0 million if the PHFU guidelines are applied prospectively.

71. Retroactive application of the PHFU guidelines would result in a $16.2 million decrease in Edison's original PHFU estimate.

72. Without application of the PHFU guidelines 56 parcels of land would remain in PHFU an average of 27 years.

73. A parcel of land valued at $520,000 was double counted in Edison's estimate of PHFU.

74. With the exception of the lag for the State income tax deduction, Edison and PSD are in agreement on the methodology for calculating working cash.

75. The appropriate working cash lag for State income taxes is under consideration generically for energy utilities in A.85-12-050.

relationships for revenue requirement increases in the intervening ECAC proceedings between general rate cases, but to hold them constant for decreases.

Findings of Fact

1. On December 26, 1986 Edison filed A.86-12-047 requesting: (1) authority to increase base rate revenues by $301.5 million or 5.4% for test year 1988, and (2) attrition increases for 1989 and 1990.

2. I.87-01-017 was issued and consolidated with A.86-12-047 on January 14, 1987 to consider a reduction in Edison's rates.

3. Edison's revised request increases base rate revenues by $79.0 million or 1.5 percent.

4. Six days of public hearings, including a Commission en banc public hearing, were held during April 1986.

5. The Administrative Law Judges' draft decision was issued on November 20, 1987.

6. Edison and PSD have agreed to a labor escalation rate of 3.5% for both 1987 and 1988.

7. Edison and PSD have agreed to the methodology for developing non-labor escalation rates and recommend rates of 2.99% for 1987 and 4.41% for 1988.

8. Edison and PSD are in agreement with respect to the forecast of kilowatt-hour sales as shown in the table Summary of Kilowatt-Hour Sales on page 6 of this decision.

9. With the exception of other operating revenues Edison and PSD have agreed to present rate revenues which include $19.4 million in CLMAC revenues.

10. Present CLMAC rates were established to recover expenses associated with conservation and load management programs incurred prior to test year 1988.

11. Edison estimated certain steam production expenses using a seven-year historical average.

76. Edison and PSD are in agreement on the method of calculating attrition and recommend that the 1989 ERAM base level should be increased by $9.8 million to reflect a decrease in FERC sales.

77. Edison and PSD have not reflected the impact of Edison's optional TOU meter plan in calculating attrition.

78. PSD has agreed to Edison's capital structure as revised in the September update hearings.

79. Edison's revised capital structure reduced its base rate revenue increase by $18 million and its total revenues including MAAC by approximately $25 million.

80. DRI's September 1987 forecast of 1988 interest rates for AA utility bonds is 10.37 percent.

81. Edison and PSD do not have the resources to develop and maintain forecasting models for interest rates.

82. DRI is a forecasting service with access to vast amounts of data and an acknowledged expertise it the forecasting of interest rates.

83. PSD's forecast of tax-exempt financing compares favorably with recent recorded data.

84. SDG&E was authorized to recover the unamortized issuance costs associated with perpetual securities in D.87-07-079.

85. The financial models of the parties provide a range for ROE of 11.5%-18.4%.

86. Interest and inflation rates have been low and relatively stable and show a considerable improvement over test year 1985.

87. Edison's recent financial performance indicates it is a strong company.

88. Edison does not face a major reasonableness review of SONGS 2 and 3.

89. Edison's MAAC rates are calculated using Edison's latest adopted ROE.

12. Edison proposes to increase accounts 512 and 513 by over 50% due to the development of new criteria for scheduling steam generating unit overhauls.

13. Edison expects the new steam generating unit overhaul criteria to reduce routine activities, but failed to quantify this benefit.

14. Repairs planned for the low pressure turbine rotor at Redondo generating station unit 7 are not performed on a routine annual basis.

15. Edison and PSD recommend that $20.5 million be adopted for test year hydro production expense.

16. Edison and PSD recommend that $17.2 million be adopted for test year other production expense.

17. Edison and PSD are in agreement with respect to the test year level of production expense for SONGS.

18. SDG&E owns a 20% share in SONGS.

19. Edison operates and maintains SONGS.

20. Edison and PSD are in agreement that it is appropriate to consider an increase in NRC fees during the test year through the attrition mechanism.

21. Edison, PSD, and FEA are in agreement with the continuation of the flexible refueling mechanism adopted in Edison's last general rate case for use with SONGS and Palo Verde refuelings.

22. For Palo Verde O&M expense Edison utilized ANPP's zero-based estimate prepared by ANPP managers and supervisors with Edison as a participant.

23. Without changing ANPP's total O&M expense estimate, Edison scaled-up the Palo Verde refueling outage expense to reflect actual experience at SONGS 2 and 3. This resulted in a reduction in ANPP's budgeted O&M expense estimate of $1.2 million.

24. Palo Verde 3 O&M and refueling expenses are addressed in this decision.

90. In 1974 Edison entered into a lease arrangement to procure its nuclear fuel requirements for SONGS. The lease permitted Edison to finance its nuclear fuel at short-term rates and was not reflected on its balance sheet.

91. An accounting change by the Financial Accounting Standards Board requires Edison, beginning in 1987, to reflect capital leases on its balance sheet.

92. Commission policy in recent years has resulted in fuel inventory assets being removed from rate base and allowed carrying costs at short-term interest rates through ECAC.

93. D.87-05-059 authorizes Edison to guarantee short- and intermediate-term debt instruments for the express purpose of financing nuclear fuel.

94. Edison is not required to terminate its lease arrangement for nuclear fuel.

95. Full recognition of SONGS and Palo Verde nuclear fuel in rate base would increase Edison's rates by $48 million.

96. Fuel is a commodity that can be used as collateral for financing and is distinguishable from fixed plant and land.

97. Carrying costs for Palo Verde nuclear fuel inventory are currently included in Edison's IMAAC.

98. Coal inventory currently receives rate base treatment.

99. Edison spent $2.4 million in affirmative case costs in anticipation of demonstrating the reasonableness of Edison's investment in Palo Verde.

100. Edison did not seek or receive approval for Palo Verde affirmative case costs or a mechanism for tracking these costs prior to their incurrence.

101. Edison has not provided value-based reliability criteria or a comprehensive study evaluating the range of alternative uses for its aging oil and gas generating units.

25. A.87-08-054 will address the implementation of rate changes associated with Palo Verde 3 O&M and refueling expenses.

26. Because of an absence of operating history at Palo Verde, PSD recommends that the O&M expense for these units be determined from the 1985 average O&M expense for 24 large nuclear units.

27. The comparative study used by PSD does not consider differences among nuclear plants, shows O&M expense varied by $20 million above or below the average, reflects an increase in 1986 of 11.8%, and does not exclude refueling expenses.

28. PSD's comparative study is useful for developing a zone of reasonabless for nuclear O&M expenses.

29. The chemical cleaning process that will be performed in conjunction with the replacement of the feedwater heaters is a one-time expense.

30. Edison plans to perform a chemical cleaning process in 1990 on SONGS 2.

31. Edison requests recovery of $2.9 million for expenses previously incurred for the reprocessing of spent nuclear fuel from SONGS 1.

32. Edison did not receive prior approval for the expenses in finding 31 nor did it receive approval of a mechanism for tracking these costs for later recovery.

33. Edison and PSD recommend that $75.3 million be adopted for test year transmission expense.

34. Edison's estimate for account 582, station expense, is based on 1985 recorded without adjustment for growth or productivity.

35. PSD's estimate for account 582 reflects recorded downward trends in labor expense and as a result is $3.5 million lower than Edison's estimate.

36. Edison has replaced a number of its tree trimming crews with contract labor and reflects this in its estimate for account 583, overhead line expense.

102. Edison agreed to provide, coincident with its fall 1988 resource plan, value-based reliability criteria which address PSD's concerns as stated in Exhibit 53.

103. With the exception of Ormand Beach unit 2 and Huntington Beach unit 2 Edison has not provided PSD with adequate justification for plant modifications or two-shifting to reduce the minimum generation capability at certain oil and gas generating units.

104. Edison requests rate base treatment for $104.6 million for the DC Expansion.

105. PSD recommends based on its cost-effective analysis that Edison be limited to recognition of an investment much less than $47.8 million.

106. Time differentiating the value of energy purchased and capacity received over the DC intertie increases PSD's cost-effectiveness analysis by $19 million.

107. Excluding 1400 MW of peaking resource additions which are are not funded or not under construction from PSD's analysis increases its recommendation by $5 million.

108. PSD's analysis of the DC Expansion was developed using forecasted gas prices based on the 1986 price of LSWR.

109. LSWR prices are subject to fluctuations and have increased sharply in 1987.

110. Edison's DC Expansion analysis does not reflect lower gas prices in 1986.

111. Averaging Edison's and PSD's forecasted gas prices increases PSD's present value of the DC Expansion $20 million.

112. Edison and PSD have jointly submitted a proposed procedure (Appendix A) which provides for modification of the existing MAAC to include recorded investment-related revenue requirement and the recorded revenues related to specific plant additions estimated to cost more than $50 million.

37. PSD's estimate for account 583 does not reflect Edison's transition to contract labor.

38. Expenses for account 597, maintenance of meters, were lower for the years 1982-1985 than for the years 1979-1981 because all purchases of meter locking rings have been assigned to the energy theft program.

39. Unlike PSD, Edison reflected the accounting change for meter locking rings in its estimate for account 597.

40. Edison's underground switch failures have increased from 27.5 per year to 85.8 per year.

41. On April 1, 1987, Edison implemented a new three-year program for the inspection of its underground facilities including a laboratory analysis of the insulating oil in all transformers and switches.

42. The increase in Edison's labor expense for the three-year underground inspection program comes from employees who were involved in new business construction. These employees will be replaced by contract crews.

43. PSD considers the increase in labor for the three-year underground inspection program to be double counting because the labor will be performed by existing employees.

44. PSD does not believe that the increase in underground equipment failures poses an immediate threat to Edison's underground distribution system and recommends against an increase in laboratory analysis.

45. A five-year average of account 598, storm damages, was adopted in Edison's last three general rate cases.

46. PSD recommends an eight-year average of account 598 be adopted to consider more years of a climatic cycle.

47. PSD has not presented evidence that more years of a climatic cycle will result in a more accurate estimate of storm damages.

113. For this rate case Edison and PSD propose that MAAC rate level increases, equal to 75% of the annualized revenue requirement, be authorized for each of four projects once they are commercially operational: Balsam Meadows, Devers-Valley-Serrano, DC Expansion, and Devers-Palo Verde.

114. The annualized CPUC jurisdictional revenue requirement for the projects to be included in MAAC is $47.7 million for Balsam Meadows, $26.0 million for Devers-Valley-Serrano, $17.7 million for DC Expansion, and $39.2 million for Devers-Palo Verde.

115. Devers-Valley-Serrano became commercially operational on July 22, 1987.

116. Edison's competing for the customer program will provide customers with the opportunity to shift loads and reduce their overall energy bills and allow Edison to operate its generating stations at higher loads and efficiencies.

117. EPRI is conducting electric transportation research.

118. Edison has not demonstrated that its electric transportation RD&D project is unique to Edison or that similar benefits cannon be obtained from EPRI.

119. Edison's alternate fuels, occupational and community safety, and advanced energy conversion RD&D programs are generally beneficial to the ratepayers, but are low priority.

120. The natural resources management program is Edison's lowest priority RD&D program.

121. Edison's actual 1988 EPRI dues are $14.7 million.

122. R.87-10-013 was issued to consider a generic proceeding for coordination and approval of all RD&D budgets.

123. Account 930.2 is a miscellaneous A&G account in which RD&D program expenditures are recorded.

124. A one-way balancing account for RD&D expenditures will insure that RD&D funds are spent on RD&D programs.

125. Edison's analysis indicates that from 1976-1985 it experienced average annual productivity gains of 1.6 percent.

48. Edison requests $4.3 million for posting termination notices on the customer's premises due to PU Section 779.1.

49. Edison has not provided the record with documentation of the study it performed from which it concluded that termination notices by telephone are not less costly than termination notices posted on the customer's premises.

50. PSD's estimated cost of providing termination notices to customers assumes that telephone notices are less costly than posting notices.

51. Edison's participation in Enercom produced savings of $225,000 in 1986 of which 10% was from former customers outside Edison's territory.

52. PSD estimates that Edison's participation in Enercom will yield savings of $775,000 in 1988 based on an increase in the number of participating utilities.

53. PSD did not present evidence that there would be an increase in the number of utilities participating in Enercom in 1988.

54. Edison's benefits from Enercom exceed its costs by six to one.

55. Edison agrees with PSD's use of a three-year average of uncollectibles.

56. Increases during the test year for items minor in nature have not been authorized in the past.

57. A minor increase for postage is likely to occur during the test year.

58. A&G expenses can be separated into two categories: items over which Edison has control and items over which Edison does not have direct control.

59. Customer growth impacts A&G expenses.

60. Customer growth from 1985 to 1988 is expected to be 8 percent.

126. PSD based on its econometric model forecasts a productivity gain of 3.4% for test year 1988.

127. The adopted operating expense as shown in Appendix C, without a productivity adjustment, yields a 2.4% productivity gain.

128. Edison and PSD were not in agreement on the data base to be used in evaluating employee compensation.

129. PSD's analysis of employee compensation did not consider total employee compensation, provide a range of data used for comparison, and adequately adjust the survey data for duplication of jobs and companies.

130. Edison and PSD are in agreement on the ratemaking treatment for gains on sales of utility assets to affiliates and net income of utility-related subsidiaries.

131. In A.87-05-007 Edison and PSD have submitted a joint exhibit agreeing to the markup royalty for services provided by the utility and the guidelines for utility employee transfers to affiliates.

132. PSD's recommended royalty to be paid by affiliates on gross revenues is addressed in A.87-05-007.

133. Edison has stipulated to PSD's recommendations for hazardous waste management.

134. PSD's hazardous waste recommendations only identify manufactured gas hazardous waste sites.

135. PSD's hazardous waste recommendations require Edison to file two different hazardous waste reports each year.

136. R.87-02-026 was initiated to address long-term goal setting, verification procedures, and annual reporting for utility F/MBE programs.

137. Edison increased its dollar awards to F/MBEs from $38.3 million in 1984 to $74.8 million in 1986 and increased the number of awards from 3,805 to 5,025 for the same period.

138. Over the last three years less than 4.5% of all contract amounts have gone to F/MBEs.

61. Pension, medical, dental, and vision plan costs, insurance, franchise taxes, and F/MBE program costs are items over which Edison does not have direct control.

62. Edison's recorded insurance premiums have generally followed market trends.

63. Recently insurance premiums have risen precipitously.

64. Some insurance professionals indicate a decline in insurance premiums.

65. Edison's estimate of insurance premiums does not reflect a softening in the insurance market.

66. Directors and officers insurance protects ratepayers and stockholders.

67. Edison and PSD have agreed to the estimated insurance premiums for crime, nuclear property, nuclear replacement generation, and nuclear liability.

68. PSD reduced Edison's estimate of group life insurance because of insufficient documentation to justify Edison's request.

69. PSD's estimate of outside provider medical costs is based on the latest recorded data and assumes no growth in participants.

70. Edison's annual energy, ECAC, and MAAC rates are calculated using Edison's latest adopted franchise tax and uncollectible rates.

71. The Superfund Tax is a new tax which Edison and experts within the utility industry have interpreted as a deductible tax.

72. Edison and PSD have incorporated the provisions of the Federal Tax Reform Act of 1986 in their tax calculations.

73. Edison estimated 1988 plant-in-service by adding forecasted plant additions from its five-year plant and work element budget to 1985 recorded plant.

74. Edison and PSD have agreed to the depreciation rates to be used in calculating depreciation expense and reserve.

75. Edison and PSD have agreed to guidelines for evaluating PHFU in future proceedings.

139. Demand side management refers to ratepayer funded programs undertaken by the utility to affect customer energy consumption patterns.

140. A determination of the appropriate funding levels for demand side management requires consideration of the current economic and resource conditions impacting the utilities regulated by this Commission.

141. The funding of demand side management programs is impacted by the Commission's elimination of the Electric Revenue Adjustment Mechanism (ERAM) for large power customers in D.87-05-071, one of the policies adopted in the 3-Rs Rulemaking to address the problems created by customer bypass of the utility system.

142. Despite the elimination of ERAM for large power customers, the Commission has determined that the most cost-effective conservation programs should still be retained for this customer group and that the utilities' incentives to pursue effective conservation remains unchanged for the commercial and residential classes who are not impacted by the elimination of ERAM.

143. The Commission continues to believe that long-range conservation remains an important goal and that utilities should continue to promote reasonable conservation and efficiency options to customers.

144. The Commission has directed utilities to refrain from using ratepayer funds for utility marketing programs aimed at increasing utility profits when ERAM is eliminated.

145. As in the case of the development of marginal costs, parties relying on computer models and related data to develop demand side management recommendations must provide this information for purposes of cross-examination and rebuttal.

146. Because the results of CEC's cost-effectiveness study were provided following the close of hearings and submission dates

76. Edison has agreed to reduce its PHFU estimate by $7.1 million if the PHFU guidelines are applied prospectively.

77. Retroactive application of the PHFU guidelines would result in a $16.2 million decrease in Edison's original PHFU estimate.

78. Without application of the PHFU guidelines 56 parcels of land would remain in PHFU an average of 27 years.

79. A parcel of land valued at $520,000 was double counted in Edison's estimate of PHFU.

80. With the exception of the lag for the State income tax deduction, Edison and PSD are in agreement on the methodology for calculating working cash.

81. The appropriate working cash lag for State income taxes is under consideration generically for energy utilities in A.85-12-050.

82. Edison and PSD are in agreement on the method of calculating attrition and recommend that the 1989 ERAM base level be increased by $9.8 million to reflect a decrease in FERC sales.

83. Edison and PSD have not reflected the impact of Edison's optional TOU meter plan in calculating attrition.

84. Appendix D sets forth a format for developing Edison's attrition filings.

85. PSD has agreed to Edison's capital structure as revised in the September update hearings.

86. Edison's revised capital structure reduced its base rate revenue increase by $18 million and its total revenues including MAAC by approximately $25 million.

87. DRI's November 1987 forecast of 1988 interest rates for AA utility bonds is 9.68%.

88. Edison and PSD do not have the resources to develop and maintain forecasting models for interest rates.

for opening and reply briefs on demand side management, this information cannot be considered part of the record in this proceeding.

147. Ethics and fairness dictate that an extension to file a brief granted to one, but not all, parties to a proceeding may not be used as an opportunity to respond to briefs which were timely filed.

148. Because the CEC inappropriately responded in its reply brief to the previously filed reply brief of PSD, that portion of CEC's reply brief cannot be considered in this proceeding.

149. PSD's proposed funding level of $1.9 million for the Residential Information program provides sufficient funds, based on an analysis of historic and current data, to provide the information necessary to communicate the need and the manner in which residential customers can conserve energy and is therefore reasonable.

150. Edison's proposed funding level of $4,149,000 for residential Energy Management Services would maintain the current audit mix and include a reasonable increase in audits under the Residential Survey Program and is therefore reasonable.

151. PSD's proposed funding level of $768,000 for residential Weatherization and Retrofit Incentives includes appropriate limitations on those incentives and designations of the areas to be targeted and is therefore reasonable.

152. The funding level of $1.4 million for Residential New Construction to which PSD and Edison have agreed provides for sufficient incentives under these programs and is therefore reasonable.

153. To ensure the proper allocation of funds for Residential New Construction, it is not necessary to adopt PSD's proposed restriction on funding for central electric heat pumps, but it is necessary to adopt PSD's recommendation regarding the elimination

89. DRI is a forecasting service with access to vast amounts of data and an acknowledged expertise it the forecasting of interest rates.

90. PSD's forecast of tax-exempt financing compares favorably with recent recorded data.

91. SDG&E was authorized to recover the unamortized issuance costs associated with perpetual securities in D.87-07-079.

92. The financial models of the parties provide a range for ROE of 11.5%-18.4%.

93. Interest and inflation rates have been low and relatively stable and show a considerable improvement over test year 1985.

94. Edison's recent financial performance indicates it is a strong company.

95. Edison does not face a major reasonableness review of SONGS 2 and 3.

96. Edison's MAAC rates are calculated using Edison's latest adopted ROE.

97. In 1974 Edison entered into a lease arrangement to procure its nuclear fuel requirements for SONGS. The lease permitted Edison to finance its nuclear fuel at short-term rates and was not reflected on its balance sheet.

98. An accounting change by the Financial Accounting Standards Board requires Edison, beginning in 1987, to reflect capital leases on its balance sheet.

99. Commission policy in recent years has resulted in fuel inventory assets being removed from rate base and allowed carrying costs at short-term interest rates through ECAC.

100. D.87-05-059 authorizes Edison to guarantee short- and intermediate-term debt instruments for the express purpose of financing nuclear fuel.

101. Edison is not required to terminate its lease arrangement for nuclear fuel.

of funding for the heat pump water heater found to be non cost-effective.

154. To ensure that ratepayer funds are applied to only efficient and cost-effective conservation programs, it is reasonable to direct Edison to investigate lower incentives for all such programs.

155. The funding level for Edison's Residential Conservation Direct Assistance program of $5.4 million, adopted in Edison's 1987 CLMAC and proposed by Cal-Neva in this proceeding, is based on the program's cost-effectiveness, the lack of market saturation by the program, the need for continued conservation by low income groups, the uncertainty of previously applied federal grants, and the questionable applicability of the 1986 cost per measure recommended by PSD in the absence of those grants, and is therefore reasonable.

156. PSD's funding recommendation of $767,000 for Non-Residential Information reflects a substantial increase over the previously authorized level, takes into account a full year of activity under the Major Accounts Representative Program, and provides adequate funding for "outreach" and is therefore reasonable.

157. PSD's recommended funding level of $8,028,358 for Non-Residential Energy Management Services is based on recent recorded costs and is therefore reasonable.

158. PSD's original funding recommendation of $1,227,000 for Non-Residential Energy Management Incentives and its originally proposed allocation of funds between small, medium, and large commercial customers ensures continuation of this program at a reasonable level to these customers, maintains cost-effective conservation programs for each of these customer groups consistent with D.87-05-071, and is therefore reasonable.

159. PSD's funding level of $0.34 million for Non-Residential Energy Management Incentives-Administration properly reflects the

102. Full recognition of SONGS and Palo Verde nuclear fuel in rate base would increase Edison's rates by $48 million.

103. Fuel is a commodity that can be used as collateral for financing and is distinguishable from fixed plant and land.

104. Carrying costs for Palo Verde nuclear fuel inventory are currently included in Edison's IMAAC.

105. Coal inventory currently receives rate base treatment.

106. Edison spent $2.4 million in affirmative case costs in anticipation of demonstrating the reasonableness of Edison's investment in Palo Verde.

107. Edison did not seek or receive approval for Palo Verde affirmative case costs or a mechanism for tracking these costs prior to their incurrence.

108. Edison has not provided value-based reliability criteria or a comprehensive study evaluating the range of alternative uses for its aging oil and gas generating units.

109. Edison agreed to provide, coincident with its fall 1988 resource plan, value-based reliability criteria which address PSD's concerns as stated in Exhibit 53.

110. With the exception of Ormand Beach unit 2 and Huntington Beach unit 2 Edison has not provided PSD with adequate justification for plant modifications or two-shifting to reduce the minimum generation capability at certain oil and gas generating units.

111. Edison requests rate base treatment for $104.6 million for the DC Expansion.

112. PSD recommends, based on its cost-effective analysis that Edison be limited to recognition of an investment much less than $47.8 million.

113. Time differentiating the value of energy purchased and capacity received over the DC intertie increases PSD's cost-effectiveness analysis by $19 million.

correlation between incentive levels and administrative costs and is therefore reasonable.

160. A funding level of $2.5 million for Non-Residential New Construction ensures that Edison can achieve the legitimate and cost-effective goals of this program even with the inclusion of large power customers and is therefore reasonable.

161. In numerous recent decisions, the Commission has considered funding for Thermal Energy Storage programs; in none of these orders or D.87-05-071, however, has the Commission determined that any load retention resulting from TES installations is the equivalent of a utility marketing function.

162. Edison's Thermal Energy Storage program is a demand side management program clearly directed to the goal of improving load management for customers installing TES equipment, is potentially able to retain customers who might otherwise have chosen self-generation, and is not specifically aimed at increasing Edison's sales and revenues.

163. The load shifting and load retention aspects of Edison's Thermal Energy Storage program, based on the previous findings, can be considered in determining the program's cost-effectiveness and funding.

164. It is reasonable to direct Edison to continue its efforts to quantify the gas-side impact of its Thermal Energy Storage program to ensure the most accurate assessment of its cost-effectiveness.

165. Edison's TES program is a cost-effective conservation program which can be extended to small, medium, and large power customers.

166. To ensure its continued cost-effectiveness, Edison's TES program should be closely monitored in the coming years through the reporting requirements established by Resolution E-3053 and the establishment, for accounting and reporting purposes, of the

114. Excluding 1400 MW of peaking resource additions which are are not funded or not under construction from PSD's analysis increases its recommendation by $5 million.

115. PSD's analysis of the DC Expansion was developed using forecasted gas prices based on the 1986 price of LSWR.

116. LSWR prices are subject to fluctuations and have increased sharply in 1987.

117. Edison's DC Expansion analysis does not reflect lower gas prices in 1986.

118. Averaging Edison's and PSD's forecasted gas prices increases PSD's present value of the DC Expansion $20 million.

119. On November 23, 1987 PSD filed a motion to set aside submission with respect to the DC Expansion project and to compel production of documents, attachment 6 to the motion.

120. Edison and LADWP signed a letter agreement dated December 2, 1985 which could impact the cost-effectiveness of the DC Expansion project by linking it with other transmission projects.

121. Edison has accepted the responsibility and attendant risk, of demonstrating the reasonableness of its investment in the DC Expansion project at the time it becomes operational.

122. Edison and PSD have jointly submitted a proposed procedure (Appendix A) which provides for modification of the existing MAAC to include recorded investment-related revenue requirement and the recorded revenues related to specific plant additions estimated to cost more than $50 million.

123. For this rate case Edison and PSD propose that MAAC rate level increases, equal to 75% of the annualized revenue requirement, be authorized for each of four projects once they are commercially operational: Balsam Meadow, Devers-Valley-Serrano, DC Expansion, and Devers-Palo Verde.

124. The annualized CPUC jurisdictional revenue requirement for the projects to be included in MAAC is $47.7 million for Balsam

categories of Load Shifting (Medium/Small and Large Customer) and Load Retention (Medium/Small and Large Customer) suggested by PSD.

167. To ensure the continuation of Edison's TES program at a cost-effective level, it is reasonable to adopt a funding level of $4 million, an amount which is based on recorded 1986 expenditures with allowances for a reasonable increase in program activity and an incentive level of $200/kW.

168. Edison's proposed funding level of $1,641,000 for its Water Storage Program ensures that the program can achieve its legitimate program goals directed at the needs of Edison's agricultural customers and is therefore reasonable.

169. To ensure the cost-effectiveness of its Water Storage Program, it is reasonable for Edison to undertake whatever reasonable cost-cutting measures are possible to limit any unnecessary and non-cost-effective spending.

170. It is appropriate to defer funding for Edison's Residential and Non-Residential Marketing programs until further analysis of the marketing issue is undertaken in the 3-Rs Rulemaking.

171. A funding level of $7,325,000 for the Measurement and Evaluation Program covers the costs associated with the technical assessments, data collection, and analysis which are required to be undertaken in this program and is therefore reasonable.

172. To ensure the proper designation of ratepayer funds, it is reasonable to include the funding for Edison's load research activities as a demand side management expense.

173. To provide consistency in the review of every utility's demand side management programs, it is reasonable for the reports required for Edison's demand side management programs to be developed using the same guidelines adopted for PG&E in D.86-12-095 at pages 111 through 118.

174. PSD's proposed funding level of $3.5 million for Edison's Support Programs take into account the needed levels of activity,

Meadow, $26.0 million for Devers-Valley-Serrano, $17.7 million for DC Expansion, and $39.2 million for Devers-Palo Verde.

125. The Devers-Valley-Serrano project became commercially operational on July 22, 1987.

126. The Balsam Meadow project became commercially operational on December 1, 1987.

127. Edison's competing for the customer program will provide customers with the opportunity to shift loads and reduce their overall energy bills and allow Edison to operate its generating stations at higher loads and efficiencies.

128. EPRI is conducting electric transportation research.

129. Edison has not demonstrated that its electric transportation RD&D project is unique to Edison or that similar benefits cannon be obtained from EPRI.

130. Edison's alternate fuels, occupational and community safety, and advanced energy conversion RD&D programs are generally beneficial to the ratepayers, but are low priority.

131. The natural resources management program is Edison's lowest priority RD&D program.

132. Edison's actual 1988 EPRI dues are $14.7 million.

133. There is a need for increased utility emphasis on long-term, end-use RD&D that is consistent with the utility's resource plan and coordinated with other California utilities and experienced research organizations.

134. The institute's recommendations may conflict with Edison's bidding procedures.

135. Edison has participated with the Council in a review of Institute proposals, and indicated that some of these projects will be funded.

136. R.87-10-013 was issued to consider a generic proceeding for coordination and approval of all RD&D budgets.

137. Account 930.2 is a miscellaneous A&G account in which RD&D program expenditures are recorded.

promotion, management, and administration to support Edison's conservation programs and is therefore reasonable.

175. It is reasonable to consolidate all demand side management program funding in base rates starting with Test Year 1988.

176. To enhance Edison's flexibility in managing its demand side management program funding, the current $2.5 million allowance for Edison to make funding shifts within the three existing major program categories (Residential Conservation, Commercial/Industrial/Agricultural Conservation, and Load Management) without a formal advice letter filing, but with notice to our Evaluation and Compliance Division.

177. For funding shifts between the three major conservation program categories or for shifts of greater than $2.5 million within those categories, Edison is required to make an advice letter filing.

178. Edison's management flexibility would not be improved by increasing the major conservation program categories as recommended by PSD, and the existing categories, named above, should be continued.

179. Edison has complied with Ordering Paragraph 12 of D.84-12-068 by reducing its Corporate Energy Management labor budget by over 20% and providing a numerical count by job category and salary range and a description of each job category.

180. The Commission's need to track conservation program spending has increased proportionately with our need to ensure the cost-effectiveness of those programs.

181. PSD's proposed uniform program definitions should be used by Edison in future rate case, offset, and advice letter filings to assist the Commission's tracking of program expenses.

182. The continued effective development of QF resources is an important goal which will permit Edison to meet its resource needs.

138. A one-way balancing account for RD&D expenditures will insure that RD&D funds are spent on RD&D programs.

139. Edison can change RD&D programs without prior Commission approval.

140. Edison's analysis indicates that from 1976-1985 it experienced average annual productivity gains of 1.6 percent.

141. PSD based on its econometric model forecasts a productivity gain of 3.4% for test year 1988.

142. The adopted operating expense as shown in Appendix C, without a productivity adjustment, yields a 2.4% productivity gain.

143. Edison and PSD were not in agreement on the data base to be used in evaluating employee compensation.

144. PSD's analysis of employee compensation did not consider total employee compensation, provide a range of data used for comparison, and adequately adjust the survey data for duplication of jobs and companies.

145. Edison and PSD are in agreement on the ratemaking treatment for gains on sales of utility assets to affiliates and net income of utility-related subsidiaries.

146. In A.87-05-007 Edison and PSD have submitted a joint exhibit agreeing to the markup royalty for services provided by the utility and the guidelines for utility employee transfers to affiliates.

147. PSD's recommended royalty to be paid by affiliates on gross revenues is addressed in A.87-05-007.

148. Edison has stipulated to PSD's recommendations for hazardous waste management.

149. PSD's hazardous waste recommendations only identify manufactured gas hazardous waste sites.

150. PSD's hazardous waste recommendations require Edison to file two different hazardous waste reports each year.

183. Overall program funding for Edison's Cogeneration/Small Power Production Program of $1,765,000, with reductions of $200,000 in 1989 and $550,000 in 1990 if warranted on the basis of a periodic analysis to be undertaken by PSD and Edison, will ensure that the legitimate goal of this program is met and its continued cost-effectiveness is monitored and is therefore reasonable.

184. Bypass is a condition which occurs when a utility customer chooses to generate its own energy rather than accept the service available from the local public utility.

185. Of particular concern is "uneconomic" bypass which occurs when a customer with self-generation costs exceeding the utility's short-run marginal costs bypasses the utility system.

186. The Commission has found that "uneconomic" bypass results in "an efficient allocation of society's resources."

187. To address the problems created by bypass for the utility and its customers, the Commission has adopted several policies in R.86-10-001, the 3-Rs (risk, return and ratemaking) rulemaking, including a commitment to revenue allocation based on Equal Percent of Marginal Cost (EPMC), the elimination of the Attrition Rate Adjustment and the Electric Revenue Adjustment Mechanism for the large light and power class, and the use of special contracts between the utilities and customers in the large light and power class.

188. While the appropriate forum for developing policies governing our response to bypass is clearly R.86-10-001, these policies play an important and integral role in our findings in this general rate case on issues related to marginal cost, revenue allocation, rate design, and demand side management programs.

189. Bypass has also been made a separate issue in this proceeding by Edison's inclusion in its prepared testimony of an exhibit intended to quantify the extent of bypass expected in the future.

151. R.87-02-026 was initiated to address long-term goal setting, verification procedures, and annual reporting for utility F/MBE programs.

152. Edison increased its dollar awards to F/MBEs from $38.3 million in 1984 to $74.8 million in 1986 and increased the number of awards from 3,805 to 5,025 for the same period.

153. Over the last three years less than 4.5% of all contract amounts have gone to F/MBEs.

154. Demand side management refers to ratepayer funded programs undertaken by the utility to affect customer energy consumption patterns.

155. A determination of the appropriate funding levels for demand side management requires consideration of the current economic and resource conditions impacting the utilities regulated by this Commission.

156. The funding of demand side management programs is impacted by the Commission's elimination of the Electric Revenue Adjustment Mechanism (ERAM) for large power customers in D.87-05-071, one of the policies adopted in the 3-Rs Rulemaking to address the problems created by customer bypass of the utility system.

157. Despite the elimination of ERAM for large power customers, the Commission has determined that the most cost-effective conservation programs should still be retained for this customer group and that the utilities' incentives to pursue effective conservation remains unchanged for the commercial and residential classes who are not impacted by the elimination of ERAM.

158. The Commission continues to believe that long-range conservation remains an important goal and that utilities should continue to promote reasonable conservation and efficiency options to customers.

190. Edison is to be commended for its attempt to quantify the effects of bypass; however, serious questions have been raised regarding the assumptions and approach used by Edison and the accessibility of Edison's models and data base.

191. Our findings in this decision regarding the use of and access to computer models in developing marginal cost estimates are equally applicable to the parties' review of Edison's model and data base used in developing its estimate of the bypass impact.

192. While forecasts of bypass may be helpful in the future to determine the impact of our remedial actions, adoption of a particular estimate of bypass is not necessary in this proceeding.

193. Because the Commission's goal is to stem the tide of uneconomic bypass, it is reasonable to continue to encourage self-generation, based on the use of renewable resources, to the extent that it is required and economically efficient.

194. With this decision, the Commission continues its commitment to marginal cost ratemaking.

195. Marginal costs provide cost-based rates and accurate price signals regarding a customer's energy consumption.

196. Uniformity between marginal costs and the related concept of avoided cost which is used as the basis for payments to qualifying facilities is appropriate to the extent possible and practicable.

197. Current methodologies for developing avoided costs must be taken into consideration in calculating QF payments.

198. In Edison's last general rate case, the Commission concluded that use of a uniform computer model in developing marginal costs would end suspicion and enhance understanding of computer models.

199. The Commission also directed Edison in its last general rate case to provide computer data upon the filing of its application to avoid the data gathering problems which PSD had experienced in that proceeding.

159. The Commission has directed utilities to refrain from using ratepayer funds for utility marketing programs aimed at increasing utility profits when ERAM is eliminated.

160. As in the case of the development of marginal costs, parties relying on computer models and related data to develop demand side management recommendations must provide this information for purposes of cross-examination and rebuttal.

161. Because the results of CEC's cost-effectiveness study were provided following the close of hearings and submission dates for opening and reply briefs on demand side management, this information cannot be considered part of the record in this proceeding.

162. Ethics and fairness dictate that an extension to file a brief granted to one, but not all, parties to a proceeding may not be used as an opportunity to respond to briefs which were timely filed.

163. Because the CEC inappropriately responded in its reply brief to the previously filed reply brief of PSD, that portion of CEC's reply brief cannot be considered in this proceeding.

164. PSD's proposed funding level of $1.9 million for the Residential Information program provides sufficient funds, based on an analysis of historic and current data, to provide the information necessary to communicate the need and the manner in which residential customers can conserve energy and is therefore reasonable.

165. Edison's proposed funding level of $4,149,000 for residential Energy Management Services would maintain the current audit mix and include a reasonable increase in audits under the Residential Survey Program and is therefore reasonable.

166. PSD's proposed funding level of $768,000 for residential Weatherization and Retrofit Incentives includes appropriate limitations on those incentives and designations of the areas to be targeted and is therefore reasonable.

200. Since the issuance of the Commission's decision in Edison's last general rate case, AB 475 has been enacted adding statutory provisions requiring, among other things, that any computer model and related data base that is the basis for any testimony or exhibit in a Commission proceeding shall be made available to the Commission and parties to hearings to the extent necessary for cross-examination and rebuttal.

201. Despite the efforts of the Commission and the Legislature, little progress toward uniformity in production cost models or availability of related data has been made within the context of the general rate case.

202. In this proceeding, instead of a uniform model being used by all parties, the Commission was presented with a total of four models, the efficacy of each of which was the subject of debate.

203. The timely provision of computer data remained a problem in this proceeding as interested parties were still without such data as hearings on the issue of marginal cost commenced.

204. The difficulty of assessing the validity of various computer models is made more acute in the setting of a general rate case in which the Commission is required to hear and decide a myriad of issues within a strict timetable.

205. The problems associated with the Commission deciding issues related to the verification of complex computer models, a significant problem in the general rate case, will worsen if IERs (incremental energy rate) are to be updated annually in ECAC proceedings which are already burdened by substantial time and staffing limitations.

206. In adopting forecasted results, the Commission must not leave to chance its understanding of the tools used to achieve those forecasts.

207. Based on the preceding findings, in the next general rate case and ECAC proceedings of Edison, PG&E, and SDG&E, it is reasonable to require all parties presenting testimony requiring

167. The funding level of $1.4 million for Residential New Construction to which PSD and Edison have agreed provides for sufficient incentives under these programs and is therefore reasonable.

168. To ensure the proper allocation of funds for Residential New Construction, it is not necessary to adopt PSD's proposed restriction on funding for central electric heat pumps, but it is necessary to adopt PSD's recommendation regarding the elimination of funding for the heat pump water heater found to be non cost-effective.

169. To ensure that ratepayer funds are applied to only efficient and cost-effective conservation programs, it is reasonable to direct Edison to investigate lower incentives for all such programs.

170. The funding level for Edison's Residential Conservation Direct Assistance program of $5.4 million, adopted in Edison's 1987 CLMAC and proposed by Cal-Neva in this proceeding, is based on the program's cost-effectiveness, the lack of market saturation by the program, the need for continued conservation by low income groups, the uncertainty of previously applied federal grants, and the questionable applicability of the 1986 cost per measure recommended by PSD in the absence of those grants and is therefore reasonable.

171. PSD's funding recommendation of $767,000 for Non-Residential Information reflects a substantial increase over the previously authorized level, takes into account a full year of activity under the Major Accounts Representative Program, and provides adequate funding for "outreach" and is therefore reasonable.

172. PSD's recommended funding level of $8,028,358 for Non-Residential Energy Management Services is based on recent recorded costs and is therefore reasonable.

173. PSD's original funding recommendation of $1,227,000 for Non-Residential Energy Management Incentives and its originally

the use of a production simulation model to develop marginal or avoided costs to provide a "base case" run using the same computer model.

208. Each party will also have the opportunity to present testimony using its model of choice and explain its preference for that model.

209. Uniformity in computer modeling, as a starting point, will aid the Commission in determining whether model, assumption, or methodological differences are causing different results.

210. It is reasonable for all parties to use the ELFIN computer model to perform the "base case" run in future rate proceedings due to its accessibility and its current application to multiple uses.

211. Any shortcomings in the ELFIN model can be addressed by each party either suggesting a means of adjusting the model to overcome any problem or citing the deficiency as a basis for reliance on an alternate model or approach.

212. To ensure access by all parties to input assumptions and data related to computer models used to calculate a utility's IERs, a uniform procedure for exchanging this information prior to hearings in ECAC and general rate case proceedings for all utilities is appropriate.

213. It is reasonable for the procedure envisioned in the above finding to include a workshop to be held no later than one week following the filing of the utility's testimony for the purposes and in the manner described in our discussion of marginal energy costs.

214. Due to greater certainty regarding the methodologies to be used for calculating marginal and avoided energy costs, it is not appropriate in this proceeding for the adopted IER to result from the averaging of the parties' proposed IERs.

215. The Commission has endorsed the calculation of two IERs -- one for marginal energy cost determinations and one for

proposed allocation of funds between small, medium, and large power customers ensures continuation of this program at a reasonable level to these customers, maintains cost-effective conservation programs for each of these customer groups consistent with D.87-05-071, and is therefore reasonable.

174. PSD's funding level of $0.34 million for Non-Residential Energy Management Incentives-Administration properly reflects the correlation between incentive levels and administrative costs and is therefore reasonable.

175. A funding level of $2.5 million for Non-Residential New Construction ensures that Edison can achieve the legitimate and cost-effective goals of this program even with the inclusion of large power customers and is therefore reasonable.

176. In numerous recent decisions, the Commission has considered funding for Thermal Energy Storage programs; in none of these orders or D.87-05-071, however, has the Commission determined that any load retention resulting from TES installations is the equivalent of a utility marketing function.

177. Edison's Thermal Energy Storage program is a demand side management program clearly directed to the goal of improving load management for customers installing TES equipment, is potentially able to retain customers who might otherwise have chosen self-generation, and is not specifically aimed at increasing Edison's sales and revenues.

178. The load shifting and load retention aspects of Edison's Thermal Energy Storage program, based on the previous findings, can be considered in determining the program's cost-effectiveness and funding.

179. It is reasonable to direct Edison to continue its efforts to quantify the gas-side impact of its Thermal Energy Storage program consistent with the recently revised Standard Practice Manual for Economic Evaluation of DSM Programs to ensure the most accurate assessment of its cost-effectiveness.

avoided energy cost determinations -- in order to properly reflect the contribution made by qualifying facilities in avoiding utility energy costs.

216. While the method for calculating avoided energy costs will ultimately be developed in A.82-04-044, et al., the Commission has continued to move in the direction of applying the "QF In/QF Out" methodology for short-run, as well as for long-run, avoided energy cost calculations.

217. Although uniformity in the calculation of marginal and avoided costs greatly simplifies the task of determining those costs, such an approach does not allow the Commission to meet its obligation of providing the most accurate prices to QFs based on avoided costs and, at the same time, to provide the most accurate price signals to consumers regarding their electric consumption.

218. PSD was the only party to this proceeding presenting IER results based on a "QF In" (marginal cost) approach and a "QF In/QF Out" approach.

219. Because PSD's IER results were the least controverted in this proceeding, reflected the proper correlation between the two resulting IER estimates, were within the range of IERs proposed by the other parties, and were derived from the same model, it is reasonable to adopt PSD's estimate of 9,626 Btu/kWh to be used for the marginal energy cost calculation and 9,775 Btu/kWh to be used for the avoided energy cost calculation.

220. It is appropriate to adopt an annual IER in this proceeding due to the likelihood of the IER being the subject of an annual update.

221. Adoption of PSD's IER estimates is not an approval of PSD's "QF In/QF Out" methodology, an issue properly reserved for A.82-04-044, et al., is not an endorsement of all of PSD's assumptions, and is not an acceptance of Edison's position that changes in such input assumptions have little impact on the calculation of the IER.

180. Edison's TES program is a cost-effective load management program which can be extended to small, medium, and large power customers.

181. To ensure its continued cost-effectiveness, Edison's TES program should be closely monitored in the coming years through the reporting requirements established by Resolution E-3053 and the establishment, for accounting and reporting purposes, of the categories of Load Shifting (Medium/Small and Large Customer) and Load Retention (Medium/Small and Large Customer) suggested by PSD.

182. To ensure the continuation of Edison's TES program at a cost-effective level, it is reasonable to adopt a funding level of $4 million, an amount which is based on recorded 1986 expenditures with allowances for a reasonable increase in program activity and an incentive level of $200/kW.

183. Edison's proposed funding level of $1,641,000 for its Water Storage Program ensures that the program can achieve its legitimate program goals directed at the needs of Edison's agricultural customers and is therefore reasonable.

184. To ensure the cost-effectiveness of its Water Storage Program, it is reasonable for Edison to undertake whatever reasonable cost-cutting measures are possible to limit any unnecessary and non-cost-effective spending.

185. It is appropriate to defer funding for Edison's Residential and Non-Residential Marketing programs until further analysis of the marketing issue is undertaken in the 3-Rs Rulemaking in which marketing issues for both ERAM and non-ERAM customers should be reviewed.

186. A funding level of $7,325,000 for the Measurement and Evaluation Program covers the costs associated with the technical assessments, data collection, and analysis which are required to be undertaken in this program and is therefore reasonable.

222. The sensitivity runs necessary to decide the issue of the impact of input assumptions on the IER calculation are not a part of the record in this proceeding.

223. The external adjustment of ELFIN model results to reflect start-up and no-load costs results in "double-counting" of those costs and is therefore inappropriate.

224. Due to the likelihood of the IER being updated on an annual basis, the resolution of the assumptions at issue in this proceeding provides useful insight into the proper determination of similar assumptions in the future.

225. The guiding principle in evaluating input assumptions is that the best assumptions embody the most up-to-date, verifiable information.

226. Based on more recent information and the correct standard of evaluation, the CCC has provided the Commission with the most reasonable assumptions regarding Edison's base load unit (coal and nuclear) production.

227. Based on the most recently available data, Edison's estimate of PNW economy energy and the CCC's estimate of PSW economy energy are reasonable.

228. The basis for determining what is a "firm" power purchase is the same in calculating an IER as it is in developing the utility's ERI (Energy Reliability Index).

229. In evaluating an agreement in terms of its inclusion as a firm resource assumption used in calculating an IER, the focus is properly on the utility's commitment to purchase the power, rather than the economic benefits of the agreement.

230. In assessing whether a utility is truly obligated in a power purchase, the totality of circumstances surrounding the contract (i.e., its status as to the two parties, its status as to the necessary governmental approval, and, least important, its acceptability as to price) must be examined.

187. •To ensure the proper designation of ratepayer funds, it is reasonable to include the funding for Edison's load research activities as a demand side management expense.

188. To provide consistency in the review of every utility's demand side management programs, it is reasonable for the reports required for Edison's demand side management programs to be developed using the same guidelines adopted for PG&E in D.86-12-095 at pages 111 through 118.

189. PSD's proposed funding level of $3.5 million for Edison's Support Programs take into account the needed levels of activity, promotion, management, and administration to support Edison's conservation programs and is therefore reasonable.

190. It is reasonable to consolidate all demand side management program funding in base rates starting with Test Year 1988 with the exception of TES incentive payments related to contracts executed prior to January 1, 1988, which should continue to be reflected in the ERAM balancing account consistent with D.82-12-055.

191. To enhance Edison's flexibility in managing its demand side management program funding, the current $2.5 million allowance for Edison to make funding shifts within the three existing major program categories (Residential Conservation, Commercial/Industrial/Agricultural Conservation, and Load Management) without a formal advice letter filing, but with notice to our Commission Advisory and Compliance Division and the Division of Ratepayer Advocates.

192. For funding shifts between the three major conservation program categories or for shifts of greater than $2.5 million within those categories, Edison is required to make an advice letter filing.

193. Edison's management flexibility would not be improved by increasing the major conservation program categories as recommended

231. Based on the criteria outlined in the preceding finding, the BPA MOU cannot be considered a firm power contract under any circumstances while the PP&L and PGE contracts, having a history of a greater level of commitment by the parties, can be considered firm purchases.

232. Based on the most recent data, the CCC's estimate of 12,694 gWh of QF generation is reasonable.

233. It is reasonable to assume that future forecasts should provide more specific and verifiable results regarding the causes and effects of minimum load conditions.

234. PSD's forecasted average price of gas of $2.52/MMBtu is accurate and therefore reasonable.

235. It is reasonable to adopt the undisputed portions of PSD's and Edison's joint exhibit on marginal energy costs and Edison's undisputed changes to factors used in the calculation of avoided energy costs to the extent that these agreements and calculations are not altered by our preceding findings.

236. In past general rate case decisions, the Commission has concluded that a suitable proxy for the marginal demand costs of generation is the annualized value of a combustion turbine.

237. The generation ($69.48,kW) and transmission ($33.10/kW) marginal demand costs jointly proposed by Edison and PSD, modified to reflect an updated O&M loading factor and the franchise fees adopted in this proceeding, are derived from the appropriate methodologies and are therefore reasonable.

238. The record in this proceeding does not include evidence to demonstrating that the basis for applying the ERI to adjust avoided capacity prices for QFs is equally applicable to an adjustment of generation marginal demand costs used for revenue allocation and rate design purposes and therefore is insufficient to justify the application of the ERI to such demand costs at this time.

by PSD, and the existing categories, named above, should be continued.

194. Edison has complied with Ordering Paragraph 12 of D.84-12-068 by reducing its Corporate Energy Management labor budget by over 20% and providing a numerical count by job category and salary range and a description of each job category.

195. The Commission's need to track conservation program spending has increased proportionately with our need to ensure the cost-effectiveness of those programs.

196. The generic demand side management definitions being established in the Reporting Requirements Manual should be used by Edison in future rate case, offset, and advice letter filings to assist the Commission's tracking of program expenses.

197. The continued effective development of QF resources is an important goal which will permit Edison to meet its resource needs.

198. Overall program funding for Edison's Cogeneration/Small Power Production Program of $1,765,000, with reductions of $200,000 in 1989 and $550,000 in 1990 if warranted on the basis of a periodic analysis to be undertaken by PSD and Edison, will ensure that the legitimate goal of this program is met and its continued cost-effectiveness is monitored and is therefore reasonable.

199. Bypass is a condition which occurs when a utility customer chooses to generate its own energy rather than accept the service available from the local public utility.

200. Of particular concern is "uneconomic" bypass.

201. The Commission has found that "uneconomic" bypass results in "an inefficient allocation of society's resources."

202. To address the problems created by bypass for the utility and its customers, the Commission has adopted several policies in R.86-10-001, the 3-Rs (risk, return and ratemaking) rulemaking, including a commitment to revenue allocation based on Equal Percent of Marginal Cost (EPMC), the elimination of the Attrition Rate Adjustment and the Electric Revenue Adjustment Mechanism for the

239. To determine the applicability of the ERI to generation marginal demand costs, it is reasonable to direct PSD and Edison to examine this issue in Edison's next general rate case.

240. The Commission has made clear that the proper calculation of avoided capacity costs requires an adjustment of the annualized value of a combustion turbine in order to reflect system reliability.

241. The Commission has indicated its preference for using an Energy Reliability Index (ERI) based on an Expected Unserved Energy (EUE) target as the basis for adjusting the value of the combustion turbine used as a proxy for avoided capacity costs.

242. The ERI proposed by Edison in this proceeding relies on a consistent and integrated set of data, employs an analytically supportable derivation of the expected unserved energy level, and is consistent with our findings in D.86-07-004 and D.86-11-071.

243. The ERI proposed by Edision is appropriate to use as the basis for calculating Edison's ERI in this proceeding as modified to correct certain flawed input assumptions related to Edison's firm resources.

244. Based on our finding that the status of a firm power purchase agreement depends on its status as to the two parties involved, the acquisition of necessary government approval, and the negotiated price, the BPA MOU cannot be included as an input assumption in calculating Edison's ERI, while the PP&L and PGE contract, which have attained greater certainty, can and were properly included as firm resource assumptions.

245. Because the ERI should equal the average EUE calculated with and without the block of additional capacity being valued, divided by the EUE target, Edison erred by failing to remove any as-available QF resources from its ERI calculation.

246. The CSC has provided a reasonable estimate of as-available QF capacity (45 MW) to be excluded from the calculation of Edison's ERI calculation.

large light and power class, and the use of special contracts between the utilities and customers in the large light and power class.

203. While the appropriate forum for developing policies governing our response to bypass is clearly R.86-10-001, these policies play an important and integral role in our findings in this general rate case on issues related to marginal cost, revenue allocation, rate design, and demand side management programs.

204. Bypass has also been made a separate issue in this proceeding by Edison's inclusion in its prepared testimony of an exhibit intended to quantify the extent of bypass expected in the future.

205. Edison is to be commended for its attempt to quantify the effects of bypass; however, serious questions have been raised regarding the assumptions and approach used by Edison and the accessibility of Edison's models and data base.

206. Our findings in this decision regarding the use of and access to computer models in developing marginal cost estimates are equally applicable to the parties' review of Edison's model and data base used in developing its estimate of the bypass impact.

207. While forecasts of bypass may be helpful in the future to determine the impact of our remedial actions, adoption of a particular estimate of bypass is not necessary in this proceeding.

208. Because the Commission's goal is to stem the tide of uneconomic bypass, it is reasonable to continue to encourage self-generation, based on the use of renewable resources, to the extent that it is required and economically efficient.

209. With this decision, the Commission continues its commitment to marginal cost ratemaking.

210. Marginal costs provide cost-based rates and accurate price signals regarding a customer's energy consumption.

211. Uniformity between marginal costs and the related concept of avoided cost which is used as the basis for payments to

247. Based on the previous findings, an ERI adjustment factor of 0.43 for 1988 is reasonable and should remain in effect until updated or revised as prescribed in A.82-04-044, et al.

248. The reinstatement of Standard Offer 2 is an action specifically reserved to A.82-04-044, et al., and will not be decided in this proceeding.

249. Although marginal distribution and marginal customer costs are distinct concepts both in terms of definition and calculation, these two costs must be examined together for the purposes of determining which of the costs of customer access to the system are attributable to marginal customer costs and which are attributable to marginal distribution costs.

250. D.86-08-083 involving PG&E's adopted marginal costs was to have served as the basis for establishing certain principles to be used in the calculation of marginal customer costs for all utilities.

251. The principles adopted in D.86-08-083 and intended to be applied to all utilities included the inclusion of marginal customers costs in the revenue allocation process; the use of the weighted average of incremental and decremental costs to calculate marginal customer costs; and the inclusion in marginal customer costs of the customer-related costs associated with meters, service drops, final line transformers, access equipment replacement and improvement, and distribution equipment directly assignable to a customer class.

252. The goal of marginal cost ratemaking is to provide accurate price signals regarding a customer's consumption and is achieved by relying on a methodology which most precisely determines the marginal cost related to customer access and maintenance on the utility system.

253. The weighted average incremental/decremental cost approach is a methodology which achieves the goal stated in the previous finding.

qualifying facilities is appropriate to the extent possible and practicable.

212. Current methodologies for developing avoided costs must be taken into consideration in calculating QF payments.

213. In Edison's last general rate case, the Commission concluded that use of a uniform computer model in developing marginal costs would end suspicion and enhance understanding of computer models.

214. The Commission also directed Edison in its last general rate case to provide computer data upon the filing of its application to avoid the data gathering problems which PSD had experienced in that proceeding.

215. Since the issuance of the Commission's decision in Edison's last general rate case, AB 475 has been enacted adding statutory provisions requiring, among other things, that any computer model and related data base that is the basis for any testimony or exhibit in a Commission proceeding shall be made available to the Commission and parties to hearings to the extent necessary for cross-examination and rebuttal.

216. Despite the efforts of the Commission and the Legislature, little progress toward uniformity in production cost models or availability of related data has been made within the context of the general rate case.

217. In this proceeding, instead of a uniform model being used by all parties, the Commission was presented with a total of three models, the efficacy of each of which was the subject of debate.

218. The timely provision of computer data remained a problem in this proceeding as interested parties were still without such data as hearings on the issue of marginal cost commenced.

219. The difficulty of assessing the validity of various computer models is made more acute in the setting of a general rate case in which the Commission is required to hear and decide a myriad of issues within a strict timetable.

254. The question of revenue shortfalls is not necessarily relevant in determining the appropriate methodology for calculating marginal costs.

255. The most equitable way in which to determine class revenue responsibility is by viewing the impact of such changes not in isolation, but in terms of their effect on a utility's total costs, a goal achieved through the Commission's adopted approach to calculating marginal costs.

256. While the parties to this proceeding generally followed the principles adopted in D.86-08-083 in making their marginal customer cost recommendations, all, except for TURN, ignored the Commission's directive to use the weighted average of incremental and decremental costs in calculating marginal customer costs.

257. In this proceeding, no "fully developed estimate" of both incremental and decremental costs has been provided.

258. Given the methodologies proposed in this proceeding, only PSD's TSM (transformer, service drop, and meter) approach is a "usable" proxy for the weighted average of incremental and decremental costs.

259. PSD's determination of incremental costs based on the TSM approach is closest to the intent of D.86-08-083 to the extent that it is a conservative estimate of those costs, a result achieved by treating final line transformers for residential and small light and power customers as demand-related costs.

260. To bring Edison's marginal customer costs closer to those intended to be implemented following D.86-08-083, it is reasonable to adopt PSD's incremental customer cost estimate exclusive of final line transformers as the proxy for the weighted average of Edison's incremental and decremental customer costs.

261. It is reasonable for the incremental cost estimate adopted in this proceeding to reflect the exclusion of line transformers for all customer classes to ensure equal treatment of these classes in the revenue allocation process.

220. The problems associated with the Commission deciding issues related to the verification of complex computer models, a significant problem in the general rate case, will worsen if IERs (incremental energy rate) are to be updated annually in ECAC proceedings which are already burdened by substantial time and staffing limitations.

221. In adopting forecasted results, the Commission must not leave to chance its understanding of the tools used to achieve those forecasts.

222. Based on the preceding findings, in the next general rate cases, ECAC proceedings, or other related proceeding identified in A.82-04-44, et al., of Edison, PG&E, and SDG&E, it is reasonable to require all parties presenting testimony requiring the use of a production simulation model to develop marginal or avoided costs to provide a "base case" run using the same computer model.

223. Each party will also have the opportunity to present testimony using its model of choice and explain its preference for that model.

224. Uniformity in computer modeling, as a starting point, will aid the Commission in determining whether model, assumption, or methodological differences are causing different results.

225. It is reasonable for all parties to use the ELFIN computer model to perform the "base case" run in future rate proceedings due to its accessibility and its current application to multiple uses.

226. Any shortcomings in the ELFIN model can be addressed by each party either suggesting a means of adjusting the model to overcome any problem or citing the deficiency as a basis for reliance on an alternate model or approach.

227. To ensure access by all parties to input assumptions and data related to computer models used to calculate a utility's IERs and marginal or avoided energy costs, a uniform procedure for exchanging this information prior to hearings in all utilities'

262. It is reasonable to direct all parties in Edison's next general rate case to base their recommended marginal customer costs on the weighted average of the utility's incremental/decremental costs.

263. Once Edison's incremental and decremental costs are properly presented, it will no longer be necessary to rely on a proxy which excludes an otherwise properly recognized customer access cost (i.e., final line transformers) from the calculation of marginal customer costs.

264. PSD's approach to calculating marginal customer costs for streetlight customers and the inclusion of those costs in the revenue allocation process is reasonable based on the Commission's approach to calculating marginal customer costs and to including streetlighting in the revenue allocation process except for the end-use costs reflected in streetlight facilities charges.

265. To ensure that all costs, including those related to distribution, are properly included in marginal customer costs, it is reasonable to direct Edison and PSD to undertake analyses and record-keeping to achieve this result.

266. Edison's and PSD's proposed marginal distribution cost, as modified to reflect our findings on marginal customer costs, is based on the appropriate methodology and should be adopted.

267. It is reasonable to direct Edison and PSD to examine the effects of basing their regression analysis used to calculate marginal distribution costs on the load measured by the sum of the maximum demands on distribution substations to ensure the most precise estimate of these costs.

268. Time-differentiated marginal costs are an important factor in developing rate design, evaluating conservation and load management programs, and making other resource decisions.

269. In adopting marginal cost time-of-use or costing periods, consideration must be given to establishing periods which maximize differences between periods and minimize differences between hours

ECACs, general rate cases, or any other proceeding adopted in A.82-04-44, et al. for updating IERs, is appropriate.

228. It is reasonable for the procedure envisioned in the above finding to include a workshop to be held no later than one week following the filing of the utility's testimony for the purposes and in the manner described in our discussion of marginal energy costs.

229. Work related to the implementation of AB 475 will ultimately determine the manner in which models are to be used and accessed.

230. Due to greater certainty regarding the methodologies to be used for calculating marginal and avoided energy costs, it is not appropriate in this proceeding for the adopted IER to result from the averaging of the parties' proposed IERs.

231. The Commission has endorsed the calculation of two IERs -- one for marginal energy cost determinations and one for avoided energy cost determinations -- in order to properly reflect the contribution made by qualifying facilities in avoiding utility energy costs.

232. While the method for calculating avoided energy costs will ultimately be developed in A.82-04-044, et al., the Commission has continued to move in the direction of applying the "QF In/QF Out" methodology for short-run, as well as for long-run, avoided energy cost calculations.

233. Although uniformity in the calculation of marginal and avoided costs greatly simplifies the task of determining those costs, such an approach does not allow the Commission to meet its obligation of providing the most accurate prices to QFs based on avoided costs and, at the same time, to provide the most accurate price signals to consumers regarding their electric consumption.

234. PSD was the only party to this proceeding presenting IER results based on a "QF In" (marginal cost) approach and a "QF In/QF Out" approach.

within those periods, to enhancing customer understanding of the periods, to ensuring continuity over time, to avoiding rate shock from changes in time periods, and to minimizing any resulting administrative burden.

270. Based on the record in this proceeding, the costing periods to which Edison and PSD have agreed are supportable and should be adopted.

271. In future rate cases, parties are encouraged to provide information aimed at improving the largely judgmental science of developing costing periods.

272. The Commission's reliance on marginal cost principles achieves equity in rates by relating the costs imposed on the utility system to the customer responsible for those costs.

273. In recent years, the Commission has adhered to a policy that, to the extent practical, total revenue should be allocated to ratepayers on the basis of their share of the utility's marginal costs.

274. In determining the appropriate methodology to use in allocating revenues, the goal of achieving marginal cost-based rates must be balanced against the potentially negative impact on certain customer groups resulting from the restructuring of revenue responsibilities.

275. The Equal Percent of Marginal Cost (EPMC) approach to revenue allocation allocates the revenue requirement on an equal basis relative to the marginal cost-based burden each customer class imposes on the system.

276. The Commission has made clear its commitment to the EPMC approach for revenue allocation as the most accurate way to reflect costs which customers impose on the system and as an effective response to the threat of bypass.

277. Based on the preceding findings, it is reasonable to adopt an EPMC revenue allocation for Edison.

235. Because PSD's IER results were the least controverted in this proceeding, reflected the proper correlation between the two resulting IER estimates, were within the range of IERs proposed by the other parties, and were derived from the same model, it is reasonable to adopt PSD's estimate of 9,626 Btu/kWh to be used for the marginal energy cost calculation and 9,775 Btu/kWh to be used for the avoided energy cost calculation.

236. It is appropriate to adopt an annual IER in this proceeding due to the likelihood of the IER being the subject of an annual update; however, this value should remain in effect until updated as prescribed in A.82-04-44, et al.

237. Adoption of PSD's IER estimates is not an approval of PSD's "QF In/QF Out" methodology, an issue properly reserved for A.82-04-044, et al., is not an endorsement of all of PSD's assumptions, and is not an acceptance of Edison's position that changes in such input assumptions have little impact on the calculation of the IER.

238. The sensitivity runs necessary to decide the issue of the impact of input assumptions on the IER calculation are not a part of the record in this proceeding.

239. Because the external adjustment of ELFIN model results to reflect start-up and no-load costs may result in "double-counting" of those costs, it is reasonable that the adjustment be reduced in the amount of the double-counting.

240. Due to the likelihood of the IER being updated on an annual basis, the resolution of the assumptions at issue in this proceeding provides useful insight into the proper determination of similar assumptions in the future.

241. The guiding principle in evaluating input assumptions is that the best assumptions embody the most up-to-date, verifiable information.

242. Based on more recent information and the correct standard of evaluation, the CCC has provided the Commission with the most

278. With the adoption of an EPMC methodology, the Commission must also consider the manner in which it will be implemented and the extent to which it will be applied to all customer classes and to all rate schedules within those classes.

279. Because Edison's present rates are currently quite far from EPMC, it is reasonable for the Commission to adopt a phase-in of the full EPMC revenue allocation adopted for Edison to mitigate the adverse impact on certain customer groups caused by the shift in revenue responsibility.

280. The most appropriate means of phasing-in EPMC is a "capping" approach which has been endorsed by the majority of the parties to this proceeding and which involves setting a percentage cap over the system average percentage change.

281. PSD's approach to phasing-in EPMC is best suited to the Commission's goals of achieving a full EPMC revenue allocation while mitigating any adverse impacts.

282. The only change required to PSD's phase-in approach is a modification of its proposed 8% cap over SAPC to a 5% cap over SAPC which will provide greater relief to those customer classes most adversely affected by the move to a full EPMC revenue allocation, while ensuring significant decreases to the large power customer group.

283. It is reasonable to adopt a single cap (5% over SAPC) to be uniformly applied to all customer classes in the absence of any evidence to support a selective application or differentiation in caps between customer groups.

284. Because of the complexities involved in PSD's proposed capping of the revenue allocation in the years between Edison's general rate cases, no caps will be adopted in this proceeding for either 1989 or 1990, and capping proposals, if necessary, will be considered on an annual basis.

285. Because the intent of this decision is to achieve a full EPMC revenue allocation for Edison by 1990, it is reasonable to

reasonable assumptions regarding Edison's base load unit (coal and nuclear) production.

243. Based on the most recently available data, Edison's estimate of PNW economy energy and the CCC's estimate of PSW economy energy are reasonable.

244. The basis for determining what is a "firm" power purchase is the same in calculating an IER as it is in developing the utility's ERI (Energy Reliability Index).

245. In evaluating an agreement in terms of its inclusion as a firm resource assumption used in calculating an IER, the focus is properly on the utility's commitment to purchase the power, rather than the economic benefits of the agreement.

246. In assessing whether a utility is truly obligated in a power purchase, the totality of circumstances surrounding the contract (i.e., its status as to the two parties, its status as to the necessary governmental approval, and, least important, its acceptability as to price) must be examined.

247. Based on the criteria outlined in the preceding finding, the BPA MOU cannot be considered a firm power contract under any circumstances while the PP&L and PGE contracts, having a history of a greater level of commitment by the parties, can be considered firm purchases.

248. Based on the most recent data, the CCC's estimate of 12,694 gWh of QF generation is reasonable.

249. It is reasonable to assume that future forecasts should provide more specific and verifiable results regarding the causes and effects of minimum load conditions.

250. PSD's forecasted average price of gas of $2.52/MMBtu is accurate and therefore reasonable.

251. It is reasonable to adopt the undisputed portions of PSD's and Edison's joint exhibit on marginal energy costs and Edison's undisputed changes to factors used in the calculation of

reflect this intent in any revenue allocation proposed for Edison in 1989 and 1990.

286. Due to our partial elimination of the Attrition Rate Adjustment (ARA) proceeding and our reliance on ECAC for PG&E revenue allocation and rate design between general rate cases, Edison's ECAC proceeding is the appropriate forum for considering any adjustments of Edison's inter-class revenue allocation in 1989 and 1990.

287. It is not reasonable for the consideration of revenue allocation issues in ECAC to include relitigation of the marginal cost structure and levels adopted in this proceeding.

288. To ensure the continued move toward an EPMC revenue allocation for Edison, it is reasonable to apply the revenue allocation approach adopted in this proceeding to rate increases or decreases for the test year 1988 to apply the revenue allocation approach adopted in Edison's 1989 and 1990 ECAC proceedings to intervening offset filings made after each of these proceedings.

289. Because of the minor nature of the adjustment involved, it is reasonable to except from the approach identified above any rate adjustments of less than 1% and allocate these increases on an equal cents per kWh basis.

290. In the absence of marginal costs calculated for the small light and power class, it is reasonable to base the intra-class revenue allocation for that class on an equal percent of present rate revenues.

291. The record is insufficient in this proceeding to order a cost-based intra-class revenue allocation for the agricultural rate schedules.

292. In the absence of a cost-based intra-class revenue allocation for the agricultural rate schedules, it is reasonable to allocate any revenue shortfall resulting from the implementation of new agricultural rate options equally among all agricultural rate schedules.

avoided energy costs to the extent that these agreements and calculations are not altered by our preceding findings.

252. In past general rate case decisions, the Commission has concluded that a suitable proxy for the marginal demand costs of generation is the annualized value of a combustion turbine.

253. The generation ($69.48,kW) and transmission ($33.10/kW) marginal demand costs jointly proposed by Edison and PSD, modified to reflect an updated O&M loading factor and the franchise fees adopted in this proceeding, are derived from the appropriate methodologies and are therefore reasonable.

254. The record in this proceeding does not include evidence to demonstrating that the basis for applying the ERI to adjust avoided capacity prices for QFs is equally applicable to an adjustment of generation marginal demand costs used for revenue allocation and rate design purposes and therefore is insufficient to justify the application of the ERI to such demand costs at this time.

255. To determine the applicability of the ERI to generation marginal demand costs, it is reasonable to direct PSD and Edison to examine this issue in Edison's next general rate case.

256. The Commission has made clear that the proper calculation of avoided capacity costs requires an adjustment of the annualized value of a combustion turbine in order to reflect system reliability.

257. The Commission has indicated its preference for using an Energy Reliability Index (ERI) based on an Expected Unserved Energy (EUE) target as the basis for adjusting the value of the combustion turbine used as a proxy for avoided capacity costs.

258. The ERI proposed by Edison in this proceeding relies on a consistent and integrated set of data, employs an analytically supportable derivation of the expected unserved energy level, and is consistent with our findings in D.86-07-004 and D.86-11-071.

293. Because it is our goal to achieve intra-class, as well as inter-class, revenue allocations based on EPMC, it is reasonable to adopt the EPMC revenue allocation to rate schedule in this proceeding for the large power customer group and to direct Edison to collect the data necessary to achieve such an intra-class revenue allocation for the small light and power and agricultural rate schedules in Edison's next general rate case.

294. Despite the low, off-peak energy usage by streetlight customers, it is energy consumption nonetheless and as such is properly included in determining class revenue allocation.

295. Because the streetlight facilities charge is related to an end-use and not to the components which are included in a marginal cost revenue allocation, it is reasonable to continue to exclude that charge from the revenue allocation process.

296. Because the contract rate schedules proposed by Edison have not been adopted in this proceeding, it is unnecessary to include any forecasted contract rate revenue deficiency in the revenue allocation process.

297. Issues related to the manner in which the revenue deficiency resulting from contract rates is to be determined and allocated are appropriately considered in the 3-Rs Rulemaking in which the guidelines for special contracts and contract rates are being developed.

298. It is reasonable to include in the revenue allocation adopted in this proceeding the total revenue requirement adopted for Edison as of January 1, 1988.

299. The Commission's current rate design philosophy is to achieve easily understood, cost-based rates which are designed to provide accurate and understandable price signals to which the customer can respond, to reflect a customer's usage patterns and characteristics, to recover the customer group's revenue requirement, and to mitigate any negative bill impacts.

259. The ERI proposed by Edision is appropriate to use as the basis for calculating Edison's ERI in this proceeding as modified to correct certain flawed input assumptions related to Edison's firm resources.

260. Based on our finding that the status of a firm power purchase agreement depends on its status as to the two parties involved, the acquisition of necessary government approval, and the negotiated price, the BPA MOU cannot be included as an input assumption in calculating Edison's ERI, while the PP&L and PGE contract, which have attained greater certainty, can and were properly included as firm resource assumptions.

261. Because the ERI should equal the average EUE calculated with and without the block of additional capacity being valued, divided by the EUE target, Edison erred by failing to remove any as-available QF resources from its ERI calculation.

262. The CSC has provided a reasonable estimate of as-available QF capacity (45 MW) to be excluded from the calculation of Edison's ERI calculation.

263. Based on the previous findings, an ERI adjustment factor of 0.43 for 1988 is reasonable and should remain in effect until updated or revised as prescribed in A.82-04-44, et al.

264. The reinstatement of Standard Offer 2 is an action specifically reserved to A.82-04-44, et al., and will not be decided in this proceeding.

265. Although marginal distribution and marginal customer costs are distinct concepts both in terms of definition and calculation, these two costs must be examined together for the purposes of determining which of the costs of customer access to the system are attributable to marginal customer costs and which are attributable to marginal distribution costs.

266. D.86-08-083 involving PG&E's adopted marginal costs was to have served as the basis for establishing certain principles to

be used in the calculation of marginal customer costs for all utilities.

267. The principles adopted in D.86-08-083 and intended to be applied to all utilities included the inclusion of marginal customers costs in the revenue allocation process; the use of the weighted average of incremental and decremental costs to calculate marginal customer costs; and the inclusion in marginal customer costs of the customer-related costs associated with meters, service drops, final line transformers, access equipment replacement and improvement, and distribution equipment directly assignable to a customer class.

268. The goal of marginal cost ratemaking is to provide accurate price signals regarding a customer's consumption and is achieved by relying on a methodology which most precisely determines the marginal cost related to customer access and maintenance on the utility system.

269. The weighted average incremental/decremental cost approach is a methodology which achieves the goal stated in the previous finding.

270. The question of revenue shortfalls is not necessarily relevant in determining the appropriate methodology for calculating marginal costs.

271. The most equitable way in which to determine class revenue responsibility is by viewing the impact of such changes not in isolation, but in terms of their effect on a utility's total costs, a goal achieved through the Commission's adopted approach to calculating marginal costs.

272. While the parties to this proceeding generally followed the principles adopted in D.86-08-083 in making their marginal customer cost recommendations, all, except for TURN, ignored the Commission's directive to use the weighted average of incremental and decremental costs in calculating marginal customer costs.

300. Our reliance on previous decisions relating to PG&E's adopted rate design is appropriate as a means of identifying current Commission rate design policy; determining whether that policy is to be continued, modified, or abandoned; and ensuring, to the extent possible, consistent treatment of all ratepayers.

301. The baseline quantities proposed by Edison and PSD, including modifications required in the seasons and allocations for Zone 15 customers, are based on the appropriate methodologies, considerations, and statutory requirements applicable to the determination of baseline allowances and are therefore reasonable.

302. It is appropriate to implement the baseline quantities adopted in this proceeding effective with the next seasonal change.

303. The goal of achieving cost based rates is not outweighed by the need for simplicity in rate design in an optional rate aimed at providing a residential customer with truly cost-based rates.

304. PSD's proposed three-tier rate achieves the goal of cost-based rates for the proposed TOU-D schedule and is therefore reasonable.

305. Edison's proposed DS schedule coupled with PSD's proposed TOU-D schedule and the parties' agreed limitations on the availability of those schedules provide, to an appropriate level of residential customers, significant options for controlling their energy usage and reducing their electric bills and are therefore reasonable.

306. The customer charge proposed by Edison and PSD for the domestic customer group, while reasonable in concept, would have an inequitable and negative impact on residential customers and would not reflect decremental customer costs.

307. Because of the shortcomings of the proposed customer charge, it is reasonable to continue Edison's minimum charge and to reject implementation of a customer charge for domestic customers at this time.

308. It is inappropriate to adjust the submetering discount under the DMS-2 schedule to reflect an allowance for distribution energy losses in the absence of a line loss study.

309. It is inappropriate to institute a balancing account for a single cost related to a specific customer group when such accounts are reserved for major proceedings affecting all utility customers.

310. Because it has been demonstrated that submetered mobilehome parks do incur distribution energy losses, it is reasonable for Edison to undertake a study to determine the actual line losses incurred by submetered mobilehome parks to ensure that the costs associated with those losses are properly reflected in the DMS-2 discount.

311. Due to questions regarding the cost-effectiveness of a line loss study for submetered mobilehome parks, it is reasonable to spread the costs of that study equally to the beneficiaries of the study -- all submetered mobilehome park owners served by Edison under the DMS-2 schedule.

312. Edison's reliance on its interpretation of Public Utilities Commission Section 739.5 to switch from a levelized to a nonlevelized fixed charge rate in calculating the DMS-2 discount is not a sufficient enough justification to warrant a change which could have serious economic repercussions for the affected customer group.

313. In order to make the change from the use of a levelized to a nonlevelized fixed charge rate in calculating the DMS-2 discount, it is necessary to know specifically whether the levelized fixed charge rate did in fact represent Edison's average costs in prior years; the extent to which those costs were understated or over-stated, if at all, by using a levelized fixed charge rate; and the extent to which it fails to represent Edison's average cost now.

273. In this proceeding, no "fully developed estimate" of both incremental and decremental costs has been provided.

274. Given the methodologies proposed in this proceeding, only PSD's TSM (transformer, service drop, and meter) approach is a "usable" proxy for the weighted average of incremental and decremental costs.

275. PSD's determination of incremental costs based on the TSM approach is closest to the intent of D.86-08-083 to the extent that it is a conservative estimate of those costs, a result achieved by treating final line transformers for residential and small light and power customers as demand-related costs.

276. To bring Edison's marginal customer costs closer to those intended to be implemented following D.86-08-083, it is reasonable to adopt PSD's incremental customer cost estimate exclusive of final line transformers as the proxy for the weighted average of Edison's incremental and decremental customer costs.

277. It is reasonable for the incremental cost estimate adopted in this proceeding to reflect the exclusion of line transformers for all customer classes to ensure equal treatment of these classes in the revenue allocation process.

278. It is reasonable to direct all electric utilities and PSD in forthcoming general rate cases to base their recommended marginal customer costs and numerical estimates of those costs on the weighted average of the utility's incremental/decremental costs.

279. Once Edison's incremental and decremental costs are properly presented, it will no longer be necessary to rely on a proxy which excludes an otherwise properly recognized customer access cost (i.e., final line transformers) from the calculation of marginal customer costs.

280. PSD's approach to calculating marginal customer costs for streetlight customers and the inclusion of those costs in the revenue allocation process is reasonable based on the Commission's

314. It is unlikely that the Legislature intended that, for purposes of determining the DMS-2 ciscount, the utility's average costs were to be developed in isolation for each test year without regard to the manner in which those costs had been determined in prior years.

315. The preceding findings justify the rejection of Edison's attempt to shift from a levelized to a nonlevelized fixed charge rate in this proceeding to calculate the DMS-2 discount.

316. A diversity benefit arises when a master-metered customer is billed more sales at baseline rates and less sales at nonbaseline rates than are actually consumed by his submetered tenants.

317. The need to adjust the submetering discount and charges for domestic master-metered customers to reflect a diversity benefit was recently been recognized by the Commission for PG&E in D.86-12-091, but the issue is a new one for Edison's mobilehome park customers.

318. The application of a diversity adjustment to correct an inequity to other customers resulting from the billing of submetered mobilehome parks is as necessary for Edison's domestic master-metered schedules as it was for PG&E.

319. The methodology for calculating the diversity adjustment is not yet perfected, Edison having insufficient time to "correct" the errors in PG&E's study and perform a study based on usage patterns of individual mobilehome parks.

320. In the absence of the appropriate study, it is reasonable and equitable to adopt a conservative estimate of the diversity adjustment.

321. WMA's proposed diversity adjustment of $1.58 is a conservative estimate, is similar to the adjustment adopted for PG&E, and is therefore reasonable.

approach to calculating marginal customer costs and to including streetlighting in the revenue allocation process except for the end-use costs reflected in streetlight facilities charges.

281. To ensure that all costs, including those related to distribution, are properly included in marginal customer costs, it is reasonable to direct Edison and PSD to undertake analyses and record-keeping to achieve this result.

282. Edison's and PSD's proposed marginal distribution cost, as modified to reflect our findings on marginal customer costs, is based on the appropriate methodology and should be adopted.

283. It is reasonable to direct Edison and PSD to examine the effects of basing their regression analysis used to calculate marginal distribution costs on the load measured by the sum of the maximum demands on distribution substations to ensure the most precise estimate of these costs.

284. Time-differentiated marginal costs are an important factor in developing rate design, evaluating conservation and load management programs, and making other resource decisions.

285. In adopting marginal cost time-of-use or costing periods, consideration must be given to establishing periods which maximize differences between periods and minimize differences between hours within those periods, to enhancing customer understanding of the periods, to ensuring continuity over time, to avoiding rate shock from changes in time periods, and to minimizing any resulting administrative burden.

286. Based on the record in this proceeding, the costing periods to which Edison and PSD have agreed are supportable and should be adopted.

287. In future rate cases, parties are encouraged to provide information aimed at improving the largely judgmental science of developing costing periods.

322. It is reasonable to apply the diversity adjustment adopted in this proceeding to reducing the submetered discount, as opposed to base rate charges, under the DMS-2 schedule.

323. To ensure an accurate estimate of the diversity adjustment for Edison's next general rate case, it is reasonable to direct Edison to derive that estimate based on a study which considers the usage patterns of mobilehome parks which it individually meters and the usage related to each master meter.

324. WMA's proposed discount for DMS-2 of $7.82 per space per month or $0.26 per space per day based on a levelized fixed charge rate and absent an allowance for distribution energy losses is reasonable subject if reduced to reflect the adopted diversity adjustment of $1.58 per space per month.

325. The above calculation yields an adopted DMS-2 discount of $6.34 per space per month.

326. A diversity benefit exists with respect to all master-metered customers and it is therefore reasonable to apply such an adjustment to Edison's DM and DMS-1 schedules.

327. A diversity factor of $2.43 for DM and DMS-1 of $2.43 per space per month or $0.08 per space per day for the DM and DMS-1 schedules represents a reduction in Edison's proposed diversity factor for these schedules proportionate with the reduction adopted for Edison's proposed DMS-2 diversity factor and is reasonable.

328. Edison's proposed discount for DMS-1 does not appear to be based on a current study.

329. A DMS-1 discount of $2.41 per space per month or $0.08 per space per day represents an increase in that discount consistent with the increase in the DMS-2 discount and based on an approach which maintains the current ratio between the DMS-1 and DMS-2 discounts and is therefore reasonable.

330. The record in this proceeding includes none of the RV park owners' alternative rate design proposals set forth in their brief.

288. The Commission's reliance on marginal cost principles achieves equity in rates by relating the costs imposed on the utility system to the customer responsible for those costs.

289. In recent years, the Commission has adhered to a policy that, to the extent practical, total revenue should be allocated to ratepayers on the basis of their share of the utility's marginal costs.

290. In determining the appropriate methodology to use in allocating revenues, the goal of achieving marginal cost-based rates must be balanced against the potentially negative impact on certain customer groups resulting from the restructuring of revenue responsibilities.

291. The Equal Percent of Marginal Cost (EPMC) approach to revenue allocation allocates the revenue requirement on an equal basis relative to the marginal cost-based burden each customer class imposes on the system.

292. The Commission has made clear its commitment to the EPMC approach for revenue allocation as the most accurate way to reflect costs which customers impose on the system and as an effective response to the threat of bypass.

293. Based on the preceding findings, it is reasonable to adopt an EPMC revenue allocation for Edison.

294. With the adoption of an EPMC methodology, the Commission must also consider the manner in which it will be implemented and the extent to which it will be applied to all customer classes and to all rate schedules within those classes.

295. Because Edison's present rates are currently quite far from EPMC, it is reasonable for the Commission to adopt a phase-in of the full EPMC revenue allocation adopted for Edison to mitigate the adverse impact on certain customer groups caused by the shift in revenue responsibility.

331. On the basis of the RV park owners having failed to present their specific rate design proposals during the course of hearings in this proceeding and thereby denying other parties and this Commission the opportunity to cross-examine or respond to those proposals, the RV park owners' alternative rate design proposals cannot be considered in this proceeding.

332. Despite this failure, the Commission is not foreclosed from considering the need for tariff changes like those proposed by the RV park owners in the future on the basis of the RV park owners' assertions regarding the residential nature of RV tenants and parks.

333. Before the Commission can consider the application of baseline allowances to RV parks, evidence must be presented which addresses the exact residence requirements to be applied to such parks and their tenants, the need for monitoring, and the appropriate charges for master-metered and submetered service for RV parks and their tenants.

334. Before a submetering discount similar to that included in the DMS-2 schedule could be applied to RV parks, evidence must be presented on the costs associated with installing, operating, and owning the submetering distribution facilities within the RV park and the propriety of applying the same statutory standards for establishing discounts for RV parks and mobilehome parks.

335. Based on the preceding findings, it is reasonable to direct Edison to conduct a study for its next general rate case of the need for and feasibility for tariff changes extending baseline allowances or master-metered discounts to RV tenants and RV park owners.

336. The agreements reached by Edison and PSD regarding the rate structures of schedules applicable to the small and medium power customer group are for the most part based on sound rate design principles and are reasonable.

296. A modification of Edison's phase-in revenue allocation approach is best suited to the Commission's goals of achieving a full EPMC revenue allocation while mitigating any adverse impacts.

297. It is reasonable for the adopted phase-in approach to move each class 1/3 of the way to full EPMC, with a cap of 5% on increases to any class in the first year with any remaining revenue decreases to be spread to the large power classes in proportion to the deviation of each class from full EPMC.

298. The adoption of a 5% cap for residential provides adequate relief from a rate shock while still providing significant rate reductions for large power customers.

299. Because the intent of this decision is to achieve a full EPMC revenue allocation for Edison by 1990, it is reasonable to reflect this intent in any revenue allocation proposed for Edison in 1989 and 1990.

300. Due to our partial elimination of the Attrition Rate Adjustment (ARA) proceeding and our reliance on ECAC for PG&E revenue allocation and rate design between general rate cases, Edison's ECAC proceeding is the appropriate forum for considering any adjustments of Edison's inter-class revenue allocation in 1989 and 1990.

301. It is not reasonable for the consideration of revenue allocation issues in ECAC to include relitigation of the marginal cost structure and levels adopted in this proceeding.

302. To ensure the continued move toward an EPMC revenue allocation for Edison, it is reasonable to allocate revenue changes to rate schedules occurring between this rate case and Edison's 1989 ECAC on the basis of the system average percentage change in order to maintain the relationships adopted in this proceeding and to identify in Edison's 1989 and 1990 ECAC proceedings the revenue

337. An exception from the above finding is Edison's and PSD's agreement to "ratchet" the demand charge for small and medium power customers.

338. "Ratcheting" refers to the setting of the demand charge at a percentage of the highest demand over a fixed period of time and has been proposed by Edison in this proceeding for all demand-metered schedules.

339. Based on the findings below which support the removal of "ratchets" proposed for demand charges for the large power customer group, it is similarly not reasonable to adopt Edison's and PSD's ratchet proposal for demand charges under the small and medium power rate schedules.

340. Edison's proposed schedule TC-1 energy rate provides proper price signals based on marginal costs and the customer's usage characteristics and is reasonable.

341. The agreements reached by Edison and PSD regarding the rate structures for the TOU-GS and TOU-GS-SOP schedules are consistent with current rate design policies and are reasonable to the extent that the "ratcheting" of demand charges under these schedules is eliminated and Edison's proposed energy charges for the two schedules are reflected.

342. Conjunctive billing for multiple meters at a single school site, subject to limitations similar to those imposed for PG&E in D.86-12-091, permits schools to realize the benefit of consolidated billing without the need to incur additional costs solely to attain that goal and is equally appropriate for Edison's school customers as it was for those located in PG&E's service territory.

343. To ensure that the benefits of conjunctive billing are realized, it is appropriate to order Edison to offer conjunctive billing for multiple meters at a single school site on an experimental basis consistent with D.86-12-091 and Resolution E-3045, to direct Edison to file an advice letter implementing the

allocation to be applied to intervening offset filings made after each of these proceedings.

303. Because of the minor nature of the adjustment involved, it is reasonable to except from the approach identified above any rate adjustments of less than 1% and allocate these increases on an equal cents per kWh basis.

304. In the absence of marginal costs calculated for the small light and power class, it is reasonable to base the intra-class revenue allocation for that class on an equal percent of present rate revenues, except for Schedules TOU-GS and GS-2 for which the revenue allocation will be determined by applying to the adopted rates the billing determinants to which Edison and PSD have agreed.

305. The record is insufficient in this proceeding to order a cost-based intra-class revenue allocation for the agricultural rate schedules.

306. In the absence of a cost-based intra-class revenue allocation for the agricultural rate schedules, it is reasonable to allocate any revenue shortfall resulting from the implementation of new agricultural rate options equally among all agricultural rate schedules.

307. Because it is our goal to achieve intra-class, as well as inter-class, revenue allocations based on EPMC, it is reasonable to adopt the EPMC revenue allocation to rate schedule in this proceeding for the large power customer group and to direct Edison to collect the data necessary to achieve such an intra-class revenue allocation for the small light and power and agricultural rate schedules in Edison's next general rate case.

308. Despite the low, off-peak energy usage by streetlight customers, it is energy consumption nonetheless and as such the energy, demand, and customer costs related to streetlighting are properly included in determining class revenue allocation.

309. Because the streetlight facilities charge is related to an end-use and not to the components which are included in a

necessary forms, and to undertake an evaluation of conjunctive billing for schools and for all customers for its next general rate case.

344. Sufficient justification has not been presented in this proceeding to enlarge the conjunctive billing program for schools to include conjunctive billing for multiple sites.

345. "Ratcheting" of demand charges is as inappropriate for schools as it is for other customer groups.

346. "Unbundled" and time-differentiated rates for schools are adequate to ensure that schools pay those costs reasonably attributable to their usage characteristics without the need to waive non-time-related demand charges.

347. Based on the above finding, it is reasonable to reject SCRUB's recommended waiver of non-time-related demand charges for schools.

348. PSD's proposed TOU-8 subschedules are in keeping with D.84-12-068 in Edison's last general rate case, provide rates related to the cost of service and load characteristics of TOU-8 customers by voltage level, and are reasonable.

349. Edison's and PSD's agreement on TOU-8 demand charges achieves, for the most part, demand charges which are cost-based and load-related and, with the elimination of "ratchets" on those charges, is reasonable.

350. In recent years, the Commission has sought to move away from the concept of ratchets based on the discriminatory effect of such a rate design tool on customer billings among customers with identical usage.

351. The use of ratchets is almost completely at odds with the Commission's efforts to accurately reflect the costs imposed by the customer on a time- and load-related basis.

352. The Commission also does not rule out the possibility that diversity in demand is reflected in non-time-related demand charges over a 12-month period.

marginal cost revenue allocation, it is reasonable to continue to exclude that charge from the revenue allocation process.

310. It is unnecessary to include any forecasted contract rate revenue deficiency in the revenue allocation process at this time.

311. Issues related to the manner in which the revenue deficiency resulting from contract rates is to be determined and allocated are appropriately considered in the 3-Rs Rulemaking in which the guidelines for special contracts and contract rates are being developed.

312. It is reasonable to include in the revenue allocation adopted in this proceeding the total revenue requirement adopted for Edison as of January 1, 1988.

313. The Commission's current rate design philosophy is to achieve easily understood, cost-based rates which are designed to provide accurate and understandable price signals to which the customer can respond, to reflect a customer's usage patterns and characteristics, to recover the customer group's revenue requirement, and to mitigate any negative bill impacts.

314. Our reliance on previous decisions relating to PG&E's adopted rate design is appropriate as a means of identifying current Commission rate design policy; determining whether that policy is to be continued, modified, or abandoned; and ensuring, to the extent possible, consistent treatment of all ratepayers.

315. The baseline quantities proposed by Edison and PSD, including modifications required in the seasons and allocations for Zone 15 customers, are based on the appropriate methodologies, considerations, and statutory requirements applicable to the determination of baseline allowances and are therefore reasonable.

316. It is appropriate to implement the baseline quantities adopted in this proceeding effective with the next seasonal change.

317. The goal of achieving cost based rates is not outweighed by the need for simplicity in rate design in an optional rate aimed at providing a residential customer with truly cost-based rates.

353. It is reasonable for the effort to unbundle rates not to be blind to detrimental impacts which may result from such design tools as ratchets.

354. Based on the preceding findings, it is reasonable to reject Edison's and PSD's proposed ratchets on demand-related meters for small, medium, and large power customer rate schedules.

355. To the extent possible each individual rate component should be based on marginal cost, and it is therefore unreasonable to limit demand charges to a certain percentage of their EPMC level.

356. Our finding regarding the impropriety of using the ERI to calculate generation marginal demand costs at this time is equally applicable to our consideration of its use in determining demand charges for TOU-8 customers.

357. It is therefore reasonable not to apply the ERI at this time to the calculation of TOU-8 demand charges, but it is reasonable to require Edison and PSD to examine the issue of its applicability for rate designpurposes in Edison's next general rate case.

358. Edison's proposed off-peak charge for TOU-8 is reasonable based on the need for consistency between the TOU-8 and TOU-GS schedules.

359. PSD's proposed real-time pricing schedule achieves the program goals of providing more specific price signals than are available under current time-of-use rates and is therefore reasonable.

360. The need for a TOU-8-SOP rate option is clear as a means of providing eligible customers with more accurate price signals and with the opportunity to change existing usage patterns in response to those signals.

361. TOU-8-SOP encourages consumption and increases sales in the off-peak period thereby offsetting any minimum load problem which Edison might experience.

318. PSD's proposed three-tier rate achieves the goal of cost-based rates for the proposed TOU-D schedule and is therefore reasonable; however, Edison should be afforded a reasonable period of time to implement the new schedule with that implementation taking effect no later than June 1, 1988.

319. It is reasonable to allocate the estimated revenue deficiency created by TOU-D to all residential customers.

320. Edison's proposed DS schedule coupled with PSD's proposed TOU-D schedule and the parties' agreed limitations on the availability of those schedules provide, to an appropriate level of residential customers, significant options for controlling their energy usage and reducing their electric bills and are therefore reasonable.

321. The customer charge proposed by Edison and PSD for the domestic customer group, while reasonable in concept, would have an inequitable and negative impact on residential customers and would not reflect decremental customer costs.

322. Because of the shortcomings of the proposed customer charge, it is reasonable to continue Edison's minimum base rate charge at $0.10/day and to reject implementation of a customer charge for domestic customers at this time.

323. It is inappropriate to adjust the submetering discount under the DMS-2 schedule to reflect an allowance for distribution energy losses in the absence of a line loss study.

324. It is inappropriate to institute a balancing account for a single cost related to a specific customer group when such accounts are reserved for major proceedings affecting all utility customers.

325. Because it has been demonstrated that submetered mobilehome parks do incur distribution energy losses, it is reasonable for Edison to undertake a study, in cooperation with WMA, to determine the actual line losses incurred by submetered

362. PSD's proposed TOU-8-SOP schedule achieves the goals of this schedule while providing an accurate estimate of the number of customers who will migrate from TOU-8 to this new schedule and is therefore reasonable.

363. In this proceeding, issues similar to those presented in our recent decisions involving PG&E's interruptible schedules (D.86-12-091 and Resolution E-3044) have been presented.

364. PSD's proposed I-6 schedule, as modified below, achieves the goal of providing cost-based rates to interruptible customers and is reasonable.

365. The penalty for failure to interrupt or curtail proposed by PSD is too harsh and would act as a significant deterrent to customers moving to this interruptible schedule.

366. The graduated approach for such penalities, as adopted in Resolution E-3044, is sufficient to ensure that an interruptible customer responds to a request by Edison to interrupt without deterring service under this schedule and is therefore reasonable to include in Edison's interruptible schedules.

367. In considering whether existing interruptible schedules I-3 and I-5 should be closed to new customers in the presence of a cost based interruptible schedule (I-6), the Commission must weigh our goal of cost-based rates against the need of interruptible customers to expect consistency in rate design for the term of the contract signed under those schedules (5 years) and the requirements of any applicable statute (i.e., Section 743 of the Public Utilities Code).

368. In balancing these interests, it is reasonable to leave the I-3 and I-5 schedules open for new customers until January 1, 1991, with language included in Edison's tariffs noticing that these schedules will be closed to new customers after that date.

369. In recognition of the reasonable expectations of existing interruptible customers, it is reasonable to permit those customers who had signed a contract with Edison under the I-3 and I-5

mobilehome parks to ensure that the costs associated with those losses are properly reflected in the DMS-2 discount.

326. Edison's reliance on its interpretation of Public Utilities Commission Section 739.5 to switch from a levelized to a nonlevelized fixed charge rate in calculating the DMS-2 discount is not a sufficient enough justification to warrant a change which could have serious economic repercussions for the affected customer group.

327. In order to make the change from the use of a levelized to a nonlevelized fixed charge rate in calculating the DMS-2 discount, it is necessary to know specifically whether the levelized fixed charge rate did in fact represent Edison's average costs in prior years; the extent to which those costs were under-stated or over-stated, if at all, by using a levelized fixed charge rate; and the extent to which it fails to represent Edison's average cost now.

328. It is unlikely that the Legislature intended that, for purposes of determining the DMS-2 discount, the utility's average costs were to be developed in isolation for each test year without regard to the manner in which those costs had been determined in prior years.

329. The preceding findings justify the rejection of Edison's attempt to shift from a levelized to a nonlevelized fixed charge rate in this proceeding to calculate the DMS-2 discount.

330. A diversity benefit arises when a master-metered customer is billed more sales at baseline rates and less sales at nonbaseline rates than are actually consumed by his submetered tenants.

331. The need to adjust the submetering discount and charges for domestic master-metered customers to reflect a diversity benefit was recently been recognized by the Commission for PG&E in D.86-12-091, but the issue is a new one for Edison's mobilehome park customers.

schedules prior to the effective date of this decision to complete that contract term under those schedules and to therefore close the I-3 and I-5 schedules for those customers effective January 1, 1993.

370. For new customers signing contracts under the I-3 and I-5 schedules between the date of this decision and January 1, 1991, it is reasonable for the terms of their contracts to provide for their termination with respect to Schedules I-3 and I-5 no later than January 1, 1993, with the remainder of the unexpired term of those contracts being served under Schedule I-6 to enable Edison to rely on the five-year commitment to interruptible service.

371. Because it has been little used by interruptible customers, it is reasonable to close Schedule I-4 effective with this decision.

372. In recognition of the cost-based nature of Schedule I-6 and the fact that the specific interruptible schedule should not alter Edison's ability to rely on that load, it is reasonable to adopt CLECA/CSPG's recommendation to permit I-3 and I-5 customers to move to I-6 at any time conditioned on the unexpired terms of the I-3 and I-5 contracts being completed under I-6.

373. PSD's proposed interruptible rates, adjusted to reflect our adopted ERI value of 0.43, most accurately reflect the value of interruptibility to Edison and are therefore reasonable.

374. Although the record in this proceeding was not sufficient to warrant a change in calculating interruptible rates to a cost-basis, it is reasonable to direct Edison and PSD to develop interruptible schedules for Edison's next general rate case based on both a cost-of-service approach and a valuation of curtailability methodology to permit the Commission to compare and determine the merits of changing the approach for determining interruptible incentives.

375. Because the 3-Rs Rulemaking (R.86-10-001) is the appropriate forum for determining terms, rates, and sales

332. The application of a diversity adjustment to correct an inequity to other customers resulting from the billing of submetered mobilehome parks is as necessary for Edison's domestic master-metered schedules as it was for PG&E.

333. The methodology for calculating the diversity adjustment is not yet perfected, Edison having insufficient time to "correct" the errors in PG&E's study and perform a study based on usage patterns of individual mobilehome parks.

334. In the absence of the appropriate study, it is reasonable and equitable to adopt a conservative estimate of the diversity adjustment.

335. WMA's proposed diversity adjustment of $1.58 is a conservative estimate, is similar to the adjustment adopted for PG&E, and is therefore reasonable.

336. It is reasonable to apply the diversity adjustment adopted in this proceeding to reducing the submetered discount, as opposed to base rate charges, under the DMS-2 schedule.

337. To ensure an accurate estimate of the diversity adjustment for Edison's next general rate case, it is reasonable to direct Edison to derive that estimate based on a study which considers the usage patterns of mobilehome parks which it individually meters and the usage related to each master meter.

338. WMA's proposed discount for DMS-2 of $7.82 per space per month or $0.26 per space per day based on a levelized fixed charge rate and absent an allowance for distribution energy losses is reasonable subject if reduced to reflect the adopted diversity adjustment of $1.58 per space per month.

339. The above calculation yields an adopted DMS-2 discount of $6.34 per space per month.

340. A diversity benefit exists with respect to all master-metered customers and it is therefore reasonable to apply such an adjustment to Edison's DM and DMS-1 schedules.

associated with special contracts and contract rates, it is not reasonable in this proceeding to adopt Edison's proposed contract schedules, TOU-CR-1 and TOU-CR-2, which would properly be presented in the context of R.86-10-001.

376. The standby charges and terms to which PSD and Edison have agreed, requiring the closing of Schedules SCG 1 through 3 and the establishment of Schedule S, properly result in the uniform treatment of standby customers and other large power customers with similar load, achieve our goal of cost-based rates, and are reasonable.

377. The continued effort to refine and clarify those costs directly imposed on the system by the self-generator in receiving standby service is appropriate.

378. It is unreasonable to "phase-in" rate increases for a single customer group (standby customers), especially when any adverse rate impacts can be more appropriately addressed through rate limiters.

379. The Commission has recognized that the full implementation of cost-based rates can result in severe bill impacts for some customers and that rate limiters provide a reasonable tool for mitigating this result.

380. The rate limiter permits the Commission to address the problems of adverse bill impacts while still ensuring marginal cost-based rates.

381. While the parties, except for PSD with respect to standby rates, did not recommend any specific level for the rate limiter, D.86-12-091 provides a reasonable formula for determining those limiters to mitigate adverse bill impacts at periods of peak demand.

382. Based on D.86-12-091, it is reasonable to adopt for Edison a summer rate limiter for primary and secondary voltage customers of 1 cent/kWh above the average summer rate for the TOU-8 secondary voltage level and an on-peak rate limiter based on the

341. A diversity factor of $2.43 for DM and DMS-1 of $2.43 per space per month or $0.08 per space per day for the DM and DMS-1 schedules represents a reduction in Edison's proposed diversity factor for these schedules proportionate with the reduction adopted for Edison's proposed DMS-2 diversity factor and is reasonable.

342. Edison's proposed discount for DMS-1 does not appear to be based on a current study.

343. A DMS-1 discount of $2.41 per space per month or $0.08 per space per day represents an increase in that discount consistent with the increase in the DMS-2 discount and based on an approach which maintains the current ratio between the DMS-1 and DMS-2 discounts and is therefore reasonable.

344. The record in this proceeding includes none of the RV park owners' alternative rate design proposals set forth in their brief.

345. On the basis of the RV park owners having failed to present their specific rate design proposals during the course of hearings in this proceeding and thereby denying other parties and this Commission the opportunity to cross-examine or respond to those proposals, the RV park owners' alternative rate design proposals cannot be considered in this proceeding.

346. Despite this failure, the Commission is not foreclosed from considering the need for tariff changes like those proposed by the RV park owners in the future on the basis of the RV park owners' assertions regarding the residential nature of RV tenants and parks.

347. Before the Commission can consider the application of baseline allowances to RV parks, evidence must be presented which addresses the exact residence requirements to be applied to such parks and their tenants, the need for monitoring, and the appropriate charges for master-metered and submetered service for RV parks and their tenants.

value of energy during the on-peak period at the coincident capacity cost plus the on-peak energy rate without capacity costs.

383. PSD's proposed rate limiter for standby customers is well-supported in this record, provides recognition of the unique usage characteristics of standby customers, and is reasonable.

384. It is reasonable to spread the revenue deficiency resulting from the imposition of the adopted rate limiters on an EPMC basis back to all customers receiving service under TOU-8.

385. The rate limiters adopted in this proceeding coupled with the reduction in rates, the use of an EPMC revenue allocation, and the rejection of demand charge ratchets, will provide reasonable and stable rates for TOU-8 customers.

386. Agricultural rates are a continual focus of concern for this Commission which, along with the Legislature, has attempted to provide for rate schedules and options which recognize the significant electrical requirement and diversity in load patterns of this customer group.

387. Edison's proposed placement of citrus growers on the three-phase GS-TP schedule with movement to PA-1 or PA-2 in three years coupled with the citrus growers' proposed amendment of Special Condition 5 of PA-1 permits citrus growers to respond to the changes in rate design adopted in this proceeding while eventually moving to cost-based rates, recognizes load conditions unique to this group of customers, and are therefore reasonable.

388. Customer charges of $10 for PA-1 customers and $20 for PA-2 customers are based on marginal customer costs, reflect the differential in marginal customers costs between these two schedules and are reasonable.

389. The demand charges proposed by Edison and PSD for the PA-1 and PA-2 schedules, modified to reduce the noncoincident demand charge for PA-2 customers by one-half to reflect differences in costs imposed by rural, as opposed to urban customers, achieves

348. Before a submetering discount similar to that included in the DMS-2 schedule could be applied to RV parks, evidence must be presented on the costs associated with installing, operating, and owning the submetering distribution facilities within the RV park and the propriety of applying the same statutory standards for establishing discounts for RV parks and mobilehome parks.

349. Based on the preceding findings, it is reasonable to direct Edison to conduct a study for its next general rate case of the need for and feasibility for tariff changes extending baseline allowances or master-metered discounts to RV tenants and RV park owners.

350. The agreements reached by Edison and PSD regarding the rate structures of schedules applicable to the small and medium power customer group are for the most part based on sound rate design principles and are reasonable.

351. An exception from the above finding is Edison's and PSD's agreement to "ratchet" the demand charge for small and medium power customers.

352. "Ratcheting" refers to the setting of the demand charge at a percentage of the highest demand over a fixed period of time and has been proposed by Edison in this proceeding for all demand-metered schedules.

353. Based on the findings below which support the removal of "ratchets" proposed for demand charges for the large power customer group, it is similarly not reasonable to adopt Edison's and PSD's ratchet proposal for demand charges under the small and medium power rate schedules.

354. Edison's proposed schedule TC-1 energy rate provides proper price signals based on marginal costs and the customer's usage characteristics and is reasonable.

355. The agreements reached by Edison and PSD regarding the rate structures for the TOU-GS and TOU-GS-SOP schedules are consistent with current rate design policies and are reasonable to

cost-based rates for the agricultural customer group and are reasonable.

390. The energy charges proposed by Edison and PSD for the PA-1 and PA-2 schedules are based on sound rate design principles and are reasonable.

391. The policy adopted in D.87-04-028 to adopt alternative service options for agricultural customers based on their needs and usage characteristics and the statutory mandate of Section 744 of the Public Utilities Code is equally applicable to Edison.

392. The PSD proposed menu of alternative service options for Edison's agricultural customers is consistent with D.87-04-028, provides a significant number of options for these customers, properly distinguishes between customers based on their demand level, and is reasonable.

393. The transfer to the agricultural class of ACWA accounts which meet the standard adopted in D.87-04-028 of customers for whom at least 70% of the water pumped by an individual account is for agricultural purposes provides appropriate service options for these agricultural customers and time periods narrower than those currently available under TOU-8 and is reasonable.

394. Based on the above finding, it is unnecessary to adopt the PA-TOU option proposed by ACWA.

395. Our inclusion of streetlighting, with respect to the energy component of streetlighting charges, and streetlighting marginal customer costs in the revenue allocation process are a recognition that these customers, despite unique traits, also share characteristics common to all other Edison customers.

396. Streetlighting customers, like other customers, can benefit from rates which reflect the costs which these customers impose on the utility system.

397. Edison's cost of service study performed for this proceeding is responsive to the Commission's directive in D.84-12-068 and is reasonable.

the extent that the "ratcheting" of demand charges under these schedules is eliminated and Edison's proposed energy charges for the two schedules are reflected.

356. Conjunctive billing for multiple meters at a single school site, subject to limitations similar to those imposed for PG&E in D.86-12-091, permits schools to realize the benefit of consolidated billing without the need to incur additional costs solely to attain that goal and is equally appropriate for Edison's school customers as it was for those located in PG&E's service territory.

357. To ensure that the benefits of conjunctive billing are realized, it is appropriate to order Edison to offer conjunctive billing for multiple meters at a single school site on an experimental basis consistent with D.86-12-091 and Resolution E-3045, to direct Edison to file an advice letter implementing the necessary forms, and to undertake an evaluation of conjunctive billing for schools and for all customers for its next general rate case.

358. Sufficient justification has not been presented in this proceeding to enlarge the conjunctive billing program for schools to include conjunctive billing for multiple sites.

359. "Ratcheting" of demand charges is as inappropriate for schools as it is for other customer groups.

360. "Unbundled" and time-differentiated rates for schools are adequate to ensure that schools pay those costs reasonably attributable to their usage characteristics without the need to waive non-time-related demand charges.

361. Based on the above finding, it is reasonable to reject SCRUB's recommended waiver of non-time-related demand charges for schools.

362. PSD's proposed TOU-8 subschedules are in keeping with D.84-12-068 in Edison's last general rate case, provide rates

398. It was appropriate for purposes of its cost of service study for Edison to rely on a Replacement Cost New methodology in the absence of adequate records upon which Edison could base an Original Cost Less Depreciation or historical cost analysis.

399. Edison's reliance on the TOU-GS schedule to calculate streetlight energy charges is misplaced and is a substantial departure from our policies emphasizing rates based on customer-imposed costs and use characteristics.

400. PSD's proposed energy and demand charges for streetlighting are based on marginal costs, reflect unallocated revenue, and are reasonable.

401. Having reflected marginal customer costs in revenues allocated to the streetlighting customer class based on a TMS (transformer, meter, service drop) approach, it is unnecessary to include an MDS (minimum distribution system) charge in streetlight rates.

402. PSD's proposed customer charges for streetlighting based on marginal customer costs are reasonable.

403. PSD's proposed streetlight facilities charges, modified to reflect its agreement with Edison of a $1.00 per lamp per year transformer charge on Edison-owned lamps, are based on the cost of those facilities at the margin, a Reproduction Cost New approach, and PSD's partial inclusion of the RO transformer and are therefore reasonable.

404. Edison's proposed rate design for streetlighting complies with our order in D.84-12-068, achieves the goal of reflecting "unbundled" rates, and is reasonable.

405. The diversity in a streetlight customer's mix of lamps and low off-peak usage should mitigate any adverse rate impacts resulting from this order, and a rate limiter for streetlight charges is therefore unnecessary.

406. The proposed charges and rate structures to which Edison, PSD, and CAL-SLA agreed are reasonable.

related to the cost of service and load characteristics of TOU-8 customers by voltage level, and are reasonable.

363. Edison's and PSD's agreement on TOU-8 demand charges achieves, for the most part, demand charges which are cost-based and load-related and, with the elimination of "ratchets" on those charges, is reasonable.

364. In recent years, the Commission has sought to move away from the concept of ratchets based on the discriminatory effect of such a rate design tool on customer billings among customers with identical usage.

365. The use of ratchets is almost completely at odds with the Commission's efforts to accurately reflect the costs imposed by the customer on a time- and load-related basis.

366. The Commission also does not rule out the possibility that diversity in demand is reflected in non-time-related demand charges over a 12-month period.

367. It is reasonable for the effort to unbundle rates not to be blind to detrimental impacts which may result from such design tools as ratchets.

368. Based on the preceding findings, it is reasonable to reject Edison's and PSD's proposed ratchets on demand-related meters for small, medium, and large power customer rate schedules.

369. To the extent possible each individual rate component should be based on marginal cost, and it is more appropriate to offset adverse rate impacts through rate limiters, rather than to limit demand charges to a certain percentage of their EPMC level.

370. Our finding regarding the impropriety of using the ERI to calculate generation marginal demand costs at this time is equally applicable to our consideration of its use in determining demand charges for TOU-8 customers.

371. It is therefore reasonable not to apply the ERI at this time to the calculation of TOU-8 demand charges, but it is reasonable to require Edison and PSD to examine the issue of its

407. For consistency in the methodology used to calculate streetlight rates, it is appropriate to rely on marginal costs to develop the customer account expense and to adopt a rate of $.12058 per lamp per month.

408. Edison's proposed cable and photocontroller charges for the DWL schedule are reasonable.

409. Based on current installation practices, CAL-SLA's Special Condition 2 for the LS-2 and LS-3 conditions is reasonable.

410. To achieve consistency with current manufacturers specifications, it is appropriate to adopt CAL-SLA's proposed language for Special Conditions 10 and 12 of the LS-2 schedule.

411. For the protection of those streetlight customers who rent streetlights from Edison, for which equipment Edison is ultimately responsible, it is reasonable to retain the current Special Condition 3 of Schedule LS-2.

412. To ensure the appropriate recovery of revenue related to Edison's optional time-of-use meters, it is reasonable to reflect the following estimate costs of those meters in the adopted results of operation: $369,500 in 1988; $1,012,600 in 1989; and $1,559,800 in 1990.

413. PSD's proposal with respect to adjustments in rate components due to revenue requirement changes occurring between general rate cases is based on increasing demand and customer charges toward their EPMC relationships for revenue requirement increases and holding them constant for decreases.

414. PSD's proposed rate design for revenue requirement changes occurring between general rate cases is consistent with our adopted rate design policies and is therefore reasonable.

415. It is appropriate for revenue changes between general rate cases attributable to energy charges to be reflected in that rate component.

applicability for rate designpurposes in Edison's next general rate case.

372. Edison's proposed off-peak energy charge for TOU-8 is reasonable based on the need for consistency between the TOU-8 and TOU-GS schedules.

373. In developing TOU-8 rates, it is reasonable to develop the interruptible credits on an incurrence, rather than an EPMC, basis.

374. To ensure that subtransmission energy rates are not nominally higher than primary voltage energy rates, it is reasonable to align these rates to be equal.

375. PSD's proposed real-time pricing schedule achieves the program goals of providing more specific price signals than are available under current time-of-use rates and is therefore reasonable.

376. The need for a TOU-8-SOP rate option is clear as a means of providing eligible customers with more accurate price signals and with the opportunity to change existing usage patterns in response to those signals.

377. TOU-8-SOP encourages consumption and increases sales in the off-peak period thereby offsetting any minimum load problem which Edison might experience.

378. PSD's proposed TOU-8-SOP schedule achieves the goals of this schedule while providing an accurate estimate of the number of customers who will migrate from TOU-8 to this new schedule and is therefore reasonable.

379. In this proceeding, issues similar to those presented in our recent decisions involving PG&E's interruptible schedules (D.86-12-091 and Resolution E-3044) have been presented.

380. PSD's proposed I-6 schedule, as modified below, achieves the goal of providing cost-based rates to interruptible customers and is reasonable.

Conclusions of Law

1. Escalation rates for labor of 3.5% in 1987 and 1988 and non-labor of 2.99% in 1987 and 4.41% in 1988 are reasonable.

2. The sales forecast shown in the table Summary of Kilowatt-Hour Sales on page 6 of this decision is reasonable.

3. CLMAC revenues should not be included in the adopted present rate revenues.

4. The present rate revenues shown in Appendix C are reasonable.

5. Edison has not provided adequate justification for its requested increase in steam generating unit overhaul expense.

6. A five-year average of steam generating unit overhaul expense is reasonable.

7. A three year interval for low pressure turbine rotor repairs is reasonable.

8. A test year hydro production expense of $20.5 million and a test year other production expense of $17.2 million are reasonable.

9. The level of SONGS production expense agreed to by Edison and PSD is reasonable.

10. Edison should be authorized to reflect an increase in NRC fees in its attrition filing.

11. A flexible refueling schedule is reasonable for SONGS and Palo Verde.

12. Edison's estimate of Palo Verde O&M expense, including refueling outage expense, is reasonable.

13. Recovery of a one-time expense for a chemical cleaning process at SONGS 3 over three years is reasonable.

14. Recovery of $2.9 million for expenses previously incurred for the reprocessing of spent nuclear fuel from SONGS 1 without Commission approval of the expenses or a tracking mechanism is inappropriate.

381. The penalty for failure to interrupt or curtail proposed by PSD is too harsh and would act as a significant deterrent to customers moving to this interruptible schedule.

382. The graduated approach for such penalities, as adopted in Resolution E-3044, is sufficient to ensure that an interruptible customer responds to a request by Edison to interrupt without deterring service under this schedule and is therefore reasonable to include in Edison's interruptible schedules.

383. In considering whether existing interruptible schedules I-3 and I-5 should be closed to new customers in the presence of a cost based interruptible schedule (I-6), the Commission must weigh our goal of cost-based rates against the need of interruptible customers to expect consistency in rate design for the term of the contract signed under those schedules (5 years) and the requirements of any applicable statute (i.e., Section 743 of the Public Utilities Code).

384. In balancing these interests, it is reasonable to leave the I-3 and I-5 schedules open for new customers until January 1, 1991, with language included in Edison's tariffs noticing that these schedules will be closed to new customers after that date.

385. In recognition of the reasonable expectations of existing interruptible customers, it is reasonable to permit those customers who had signed a contract with Edison under the I-3 and I-5 schedules prior to the effective date of this decision to complete that contract term under those schedules and to therefore close the I-3 and I-5 schedules for those customers effective January 1, 1993.

386. For new customers signing contracts under the I-3 and I-5 schedules between the date of this decision and January 1, 1991, it is reasonable for the terms of their contracts to provide for their termination with respect to Schedules I-3 and I-5 no later than January 1, 1993, with the remainder of the unexpired term of those

15. A test year transmission expense of $75.3 million is reasonable.

16. PSD's $3.5 million reduction to Edison's estimate for account 582 reflects recorded downward trends in labor expenses is reasonable.

17. It is reasonable to reflect Edison's transition to contract labor for tree trimming in account 583.

18. It is reasonable to reflect the accounting change for purchases of meter locking rings in account 597.

19. Edison's estimated cost for its three-year underground inspection program is reasonable.

20. A five-year average of storm damages is reasonable.

21. Edison has not provided adequate justification for its estimated cost of providing termination notices to customers.

22. PSD's estimated cost for providing termination notices to customers is reasonable.

23. Edison's 1986 savings of $225,000 should be included in the calculation of its uncollectible rate.

24. An uncollectible rate of .214% and a franchise tax rate of .73% are reasonable.

25. Edison should be authorized to reflect an increase in postage expense in its attrition filing.

26. It is reasonable to limit the growth from 1985-1988 in A&G expense items over which Edison has control to 8%, the expected customer growth from 1985-1988.

27. A 10% reduction in Edison's estimated cost of general insurance, comprehensive general liability insurance, and directors and officers insurance is reflective of market trends and should be adopted.

28. PSD's estimated cost of group life insurance is reasonable.

29. PSD's estimated cost of outside provider medical costs adjusted for employee growth is reasonable.

contracts being served under Schedule I-6 to enable Edison to rely on the five-year commitment to interruptible service.

387. Because of their lack of use by interruptible customers, it is reasonable to eliminate Schedule I-4 effective with this decision and to close Schedule I-2.

388. In recognition of the cost-based nature of Schedule I-6 and the fact that the specific interruptible schedule should not alter Edison's ability to rely on that load, it is reasonable to adopt CLECA/CSPG's recommendation to permit I-3 and I-5 customers to move to I-6 at any time conditioned on the unexpired terms of the I-3 and I-5 contracts being completed under I-6.

389. It is reasonable to adopt the two super off-peak interruptible rate options to which Edison and PSD have agreed.

390. It is reasonable to develop credits and penalties under Schedules I-1, I-2, I-3, and I-5 consistent with our discussion in this decision.

391. PSD's proposed interruptible rates, adjusted to reflect our adopted ERI value of 0.43, most accurately reflect the value of interruptibility to Edison and are therefore reasonable.

392. Although the record in this proceeding was not sufficient to warrant a change in calculating interruptible rates to a cost-basis, it is reasonable to direct Edison and PSD to develop interruptible schedules for Edison's next general rate case based on both a cost-of-service approach and a valuation of curtailability methodology to permit the Commission to compare and determine the merits of changing the approach for determining interruptible incentives.

393. Because the 3-Rs Rulemaking (R.86-10-001) is the appropriate forum for determining terms, rates, and sales associated with special contracts and contract rates, it is not reasonable in this proceeding to adopt Edison's proposed generic special contract schedule, TOU-CR-2, which would properly be presented in the context of R.86-10-001.

30. The Superfund Tax should be used as a deduction for calculating income taxes.

31. It is reasonable to reflect the provisions of the Federal Tax Reform Act of 1986 in calculating income taxes.

32. Edison's estimated 1988 plant-in-service is reasonable.

33. The depreciation rates agreed to by Edison and PSD are reasonable.

34. The guidelines for evaluating PHFU are reasonable and should be adopted for all items in PHFU starting January 1, 1989.

35. The Evaluation and Compliance Division should notify all energy utilities under CPUC jurisdiction that we expect guidelines for evaluating PHFU to be addressed in their next general rate case.

36. A $7.5 million reduction to Edison's estimate of PHFU is reasonable.

37. This proceeding should remain open to consider any changes in the calculation of working cash allowance adopted in A.86-12-050.

38. The method of calculating attrition agreed to by Edison and PSD is reasonable.

39. The 1989 ERAM base level should be increased by $9.8 million to reflect a decrease in FERC sales.

40. The impact of Edison's optional TOU meter plan should be reflected in calculating attrition.

41. Edison's capital structure as revised in the September update hearings is reasonable.

42. An incremental cost of long-term debt of 10.37% is reasonable.

43. PSD's forecast of tax-exempt financing is reasonable.

44. Edison should be authorized to recover the costs associated with perpetual securities.

45. A ROE of 12.75% is reasonable and should be adopted.

394. It is appropriate to authorize the TOU-CR-1 tariff as part of Edison's tariff structure and direct that it be covered by ERAM until such time as a decision in R.86-10-001 separates Edison's customers into an ERAM and a non-ERAM group.

395. The standby charges and terms to which PSD and Edison have agreed, requiring the closing of Schedules SCG 1 through 3 and the establishment of Schedule S, properly result in the uniform treatment of standby customers and other large power customers with similar load, achieve our goal of cost-based rates, and are reasonable.

396. The continued effort to refine and clarify those costs directly imposed on the system by the self-generator in receiving standby service is appropriate.

397. It is unreasonable to "phase-in" rate increases for a single customer group (standby customers), especially when any adverse rate impacts can be more appropriately addressed through rate limiters.

398. The Commission has recognized that the full implementation of cost-based rates can result in severe bill impacts for some customers and that rate limiters provide a reasonable tool for mitigating this result.

399. The rate limiter permits the Commission to address the problems of adverse bill impacts while still ensuring marginal cost-based rates.

400. While the parties, except for PSD with respect to standby rates, did not recommend any specific level for the rate limiter, D.86-12-091 provides a reasonable formula for determining those limiters to mitigate adverse bill impacts at periods of peak demand.

401. Based on D.86-12-091 and PSD's well-supported showing on standby rate limiters, it is reasonable to adopt rate limiters for TOU-8 and standby customers consistent with our discussion in this decision.

46. Edison's MAAC rates for SONGS 2 and 3 post-commercial operating date and Section 463 projects should be adjusted to reflect a ROE of 12.75%. Edison's base rate revenue requirement for SONGS 2 and 3 pre-commercial operating costs and Palo Verde should also reflect a 12.75% ROE.

47. Carrying costs on nuclear fuel inventory and coal inventory should be calculated using Edison's ECAC interest rate and recorded in the ECAC account.

48. Recovery of $2.4 million for expenses previously incurred for Palo Verde affirmative case costs without Commission approval of the expenses or a tracking mechanism is inappropriate.

49. Edison should provide, coincident with its fall 1988 resource plan, value-based reliability criteria and a comprehensive study evaluating the range of alternative uses for its aging oil and gas generating units. These should be designed to address PSD's concerns as stated in Exhibit 53.

50. Edison should be authorized to request funding for plant modification or two-shifting to reduce minimum generation capability at certain oil and gas generating units.

51. A cost cap of $91.8 million for Edison's share of the DC Expansion is reasonable.

52. The proposed procedure, attached as Appendix A, which provides for modification of Edison's MAAC to include the recorded investment-related revenue requirement and the recorded revenues related to specific plant additions estimated to cost more than $50 million is reasonable and should be adopted.

53. Edison should be authorized to file for an increase in the MAAC rate, subject to refund, equal to 75% of the annualized investment-related revenue requirement for the Balsam Meadows, Devers-Valley-Serrano, DC Expansion, and Devers-Palo Verde projects. Edison's filing should be by an advice letter submitted after each project becomes commercially operational.

402. It is reasonable to spread the revenue deficiency resulting from the imposition of the adopted rate limiters on an EPMC basis back to all customers receiving service under TOU-8.

403. The rate limiters adopted in this proceeding coupled with the reduction in rates, the use of an EPMC revenue allocation, and the rejection of demand charge ratchets, will provide reasonable and stable rates for TOU-8 customers.

404. Agricultural rates are a continual focus of concern for this Commission which, along with the Legislature, has attempted to provide for rate schedules and options which recognize the significant electrical requirement and diversity in load patterns of this customer group.

405. Edison's proposed placement of citrus growers on the three-phase GS-TP schedule with movement to PA-1 or PA-2 in three years coupled with the citrus growers' proposed amendment of Special Condition 5 of PA-1 when made comparable to special condition 5 for PA-2, permits citrus growers to respond to the changes in rate design adopted in this proceeding while eventually moving to cost-based rates, recognizes load conditions unique to this group of customers, and are therefore reasonable.

406. Customer charges of $10 for PA-1 customers and $20 for PA-2 customers are based on marginal customer costs, reflect the differential in marginal customers costs between these two schedules and are reasonable.

407. The demand charges proposed by Edison and PSD for the PA-1 and PA-2 schedules, modified to reduce the noncoincident demand charge for PA-2 customers and the connect charge for PA-1 customers by one-half to reflect differences in costs imposed by rural, as opposed to urban customers, achieves cost-based rates for the agricultural customer group and are reasonable.

408. The energy charges proposed by Edison and PSD for the PA-1 and PA-2 schedules are based on sound rate design principles and are reasonable.

54. Edison should file an application to determine the reasonable and prudent costs of each project not later than six months after the final portion of each project is placed in-service.

55. Edison's MAAC revenue requirement should be increased by $26.0 million for Devers-Valley-Serrano and the MAAC rate should be increased by $19.5 million or 0.030 cents/kWh, subject to refund.

56. In order to insure continued consistency of ratemaking treatment, SDG&E's portion of SONGS O&M expenses billed to it by Edison should be reflected in future SDG&E base rate changes at the level adopted by this order.

57. Edison's requested funding for the competing for the customer RD&D program is reasonable.

58. Edison's requested funding for the electric transportation RD&D project should be reduced to $100,000 for monitoring the work of others.

59. Edison should be authorized to spend $900,000 on its alternate fuels, occupational and community safety, and advanced energy conversion RD&D programs.

60. Edison's natural resources management RD&D program should not be funded.

61. Edison's actual 1988 EPRI dues of $14.7 million should be authorized in rates.

62. All RD&D program expenditures should be recorded in account 930.2.

63. A one-way balancing account for RD&D expenditures should be adopted.

64. A productivity gain of approximately 2.6% for 1988 is reasonable.

65. Edison and PSD should jointly develop a data base for use in evaluating employee compensation in Edison's next general rate case.

409. The policy adopted in D.87-04-028 to adopt alternative service options for agricultural customers based on their needs and usage characteristics and the statutory mandate of Section 744 of the Public Utilities Code is equally applicable to Edison.

410. The PSD proposed menu of alternative service options for Edison's agricultural customers is consistent with D.87-04-028, provides a significant number of options for these customers, properly distinguishes between customers based on their demand level, and is reasonable.

411. The mandatory transfer from TOU-8 to the agricultural class of ACWA accounts or other large pumping accounts which meet the standard adopted in D.87-04-028 of customers for whom at least 70% of the water pumped by an individual account is for agricultural purposes provides appropriate service options for these agricultural customers and time periods narrower than those currently available under TOU-8 and is reasonable.

412. Based on the above finding, it is unnecessary to adopt the PA-TOU option proposed by ACWA.

413. It is reasonable to permit Edison to implement the new agricultural tariff options no later than June 1, 1988 due to the need to inform customers of the changes and install required metering.

414. It is reasonable to direct Edison to conduct, in cooperation with PSD, workshops to explain and refine the agricultural tariff options adopted in this decision.

415. Our inclusion of streetlighting, with respect to the energy component of streetlighting charges, and streetlighting marginal customer costs in the revenue allocation process are a recognition that these customers, despite unique traits, also share characteristics common to all other Edison customers.

416. Streetlighting customers, like other customers, can benefit from rates which reflect the costs which these customers impose on the utility system.

66. Edison's and PSD's agreement on ratemaking treatment for gains on sales of utility assets to affiliates, net income of utility-related subsidiaries, markup royalty for services provided by the utility, and guidelines for utility employee transfers to affiliates is reasonable and should be adopted.

67. PSD's recommended royalty to be paid by affiliates on gross revenues should not be adopted.

68. PSD's hazardous waste management recommendations are reasonable and should be adopted as modified below.

69. PSD's recommendations concerning manufactured gas hazardous waste sites should be expanded to include all hazardous waste sites.

70. Edison should be allowed to combine the two different annual hazardous waste reports PSD recommends into one annual report.

71. Long-term goal setting, verification procedures, and annual reporting for utility F/MBE programs should be addressed in R.87-02-026.

72. Edison had a significant increase in the amount and number of its contract awards to F/MBEs from 1984-1986.

73. Edison should achieve significant increases in the amount and number of contract awards to F/MBEs for future proceedings.

74. Ethics and fairness dictate that an extension to file a brief granted to one, but not all, parties to a proceeding should not be used as an opportunity to respond to briefs which were timely filed.

75. Edison should continue to promote reasonable and cost-effective conservation measures and efficiency options for its customers.

76. To ensure its continued cost-effectiveness, Edison should closely monitor its Thermal Energy Storage program in coming years through the reporting requirements established in Resolution E-3053 and the establishment, for accounting and reporting purposes, of

417. Edison's cost of service study performed for this proceeding is responsive to the Commission's directive in D.84-12-068 and is reasonable.

418. It was appropriate for purposes of its cost of service study for Edison to rely on a Replacement Cost New methodology in the absence of adequate records upon which Edison could base an Original Cost Less Depreciation or historical cost analysis.

419. Edison's reliance on the TOU-GS schedule to calculate streetlight energy charges is misplaced and is a substantial departure from our policies emphasizing rates based on customer-imposed costs and use characteristics.

420. PSD's proposed energy and demand charges for streetlighting are based on marginal costs, reflect unallocated revenue, and are reasonable.

421. Having reflected marginal customer costs in revenues allocated to the streetlighting customer class based on a TMS (transformer, meter, service drop) approach, it is unnecessary to include an MDS (minimum distribution system) charge in streetlight rates.

422. PSD's proposed customer charges for streetlighting based on marginal customer costs are reasonable.

423. PSD's proposed streetlight facilities charges, modified to reflect its agreement with Edison of a $1.00 per lamp per year transformer charge on Edison-owned lamps, are based on the cost of those facilities at the margin, a Reproduction Cost New approach, and PSD's partial inclusion of the RO transformer and are therefore reasonable.

424. Edison's proposed rate design for streetlighting complies with our order in D.84-12-068, achieves the goal of reflecting "unbundled" rates, and is reasonable.

425. The diversity in a streetlight customer's mix of lamps and low off-peak usage should mitigate any adverse rate impacts

the categories of Load Shifting (Medium/Small and Large Customer) and Load Retention (Medium/Small and Large Customer).

77. Edison should be directed to continue its efforts to quantify the gas-side impacts of its Thermal Energy Storage program.

78. To ensure the continued cost-effectiveness of its Water Storage Program; Edison should undertake whatever reasonable cost-cutting measures are possible to limit any unnecessary and non-cost-effective spending.

79. Funding for Edison's Residential and Non-Residential Marketing programs should be deferred until further analysis of the marketing issue is undertaken in the 3-Rs Rulemaking, R.86-10-001.

80. Edison should develop the reports required for its demand side management programs using the same guidelines adopted for PG&E in D.86-12-095 at pages 111 through 118.

81. PSD's uniform program definitions for demand side management programs should be used by Edison in all future rate case, offset, and advice letter filings.

82. The funding levels found reasonable in this decision for Edison's demand side management programs should be adopted with an overall funding level of $54,194,000.

83. All demand side management program funding should be consolidated and placed in base rates starting with the test year 1988.

84. Edison should continue to be allowed to make funding shifts of $2.5 million within the three major demand side management categories without an advice letter, but with notice to the Commission's Evaluation and Compliance Division.

85. Edison should be required to file an advice letter for funding shifts between the three major demand side management program categories or for shifts of greater than $2.5 million within those categories.

resulting from this order, and a rate limiter for streetlight charges is therefore unnecessary.

426. The proposed charges and rate structures to which Edison, PSD, and CAL-SLA agreed are reasonable.

427. For consistency in the methodology used to calculate streetlight rates, it is appropriate to rely on marginal costs to develop the customer account expense and to adopt a rate of $.12058 per lamp per month.

428. Edison's proposed cable and photocontroller charges for the DWL schedule are reasonable.

429. Based on current installation practices, CAL-SLA's Special Condition 2 for the LS-2 and LS-3 conditions is reasonable.

430. To achieve consistency with current manufacturers specifications, it is appropriate to adopt CAL-SLA's proposed language for Special Conditions 10 and 12 of the LS-2 schedule.

431. For the protection of those streetlight customers who rent streetlights from Edison, for which equipment Edison is ultimately responsible, it is reasonable to retain the current Special Condition 3 of Schedule LS-2.

432. To ensure the appropriate recovery of revenue related to Edison's optional time-of-use meters, it is reasonable to reflect the following estimate costs of those meters in the adopted results of operation: $369,500 in 1988; $1,012,600 in 1989; and $1,559,800 in 1990.

433. PSD's proposal with respect to adjustments in rate components due to revenue requirement changes occurring between general rate cases is based on increasing demand and customer charges toward their EPMC relationships for revenue requirement increases and holding them constant for decreases.

434. PSD's proposed rate design for revenue requirement changes occurring between general rate cases is consistent with our adopted rate design policies and is therefore reasonable.

86. Edison should continue the effective development of QF resources.

87. The overall funding for Edison's Cogeneration/Small Power Production Program of $1,765,000, with reductions of $200,000 in 1989 and $550,000 in 1990, if warranted on the basis of a periodic analysis to be undertaken by Edison and PSD, found reasonable in this proceeding should be adopted.

88. The results of operation as set forth in Appendixes C and D are reasonable and should be adopted.

89. Based on the foregoing findings and conclusions a $56.0 million decrease in Edison's base rate revenues is just and reasonable and should be adopted.

90. The Commission's findings in this general rate case on issues related to marginal cost, revenue allocation, rate design, and demand side management programs should take into consideration the policies adopted in R.86-10-001 to address the problem of uneconomic bypass.

91. Marginal costs should continue to be the basis for the revenue allocation and rate design adopted in this proceeding.

92. In the future general rate case and ECAC proceedings of Edison, PG&E, and SDG&E, all parties presenting testimony requiring the use of a production simulation model to develop marginal or avoided costs should provide a "base case" run using the ELFIN model.

93. To ensure access by all parties to input assumptions and data related to computer models used to calculate a utility's IERs, a workshop should be held no later than one week following the filing of testimony by either Edison, PG&E, or SDG&E in their respective ECAC or general rate case proceedings.

94. The purpose of the workshop referenced in the preceding conclusion should be (1) to determine the data sets, resource plans, load shape, heat rate input, unit commitment and dispatch, minimum load conditions, resource assumptions, marginal fuel

Conclusions of Law

1. Escalation rates for labor of 3.5% in 1987 and 1988 and non-labor of 2.99% in 1987 and 4.41% in 1988 are reasonable.

2. The sales forecast shown in the table Summary of Kilowatt-Hour Sales on page 8 of this decision is reasonable.

3. CLMAC revenues should not be included in the adopted present rate revenues.

4. The present rate revenues shown in Appendix C are reasonable.

5. Edison has not provided adequate justification for its requested increase in steam generating unit overhaul expense.

6. A seven-year average of steam generating unit overhaul expense is reasonable.

7. A three year interval for low pressure turbine rotor repairs is reasonable.

8. A test year hydro production expense of $20.5 million and a test year other production expense of $17.2 million are reasonable.

9. The level of SONGS production expense agreed to by Edison and PSD is reasonable.

10. SONGS O&M expense should not be relitigated in SDG&E's general rate case.

11. SDG&E should be authorized to reflect in future base rate filings the level of SONGS O&M expense, adjusted for inflation, adopted in this decision.

12. Edison should be authorized to reflect an increase in NRC fees in its attrition filing.

13. A flexible refueling schedule is reasonable for SONGS and Palo Verde.

14. Edison's estimate of Palo Verde O&M expense, including refueling outage expense, is reasonable.

assumptions, and all other pertinent data which the utility has used to calculate its IER and (2) to provide a forum in which agreements between the parties can be reached.

95. Two IERs should be adopted in this proceeding, one for use in the calculation of marginal energy costs and one for use in the calculation of avoided energy costs, based on methodologies which reflect the differences in these two costs.

96. The annual IERs found reasonable in this decision should be adopted.

97. In the calculation of IERs, the ELFIN model should not be externally adjusted to reflect start-up and no-load costs.

98. The input assumptions used in calculating marginal and avoided energy costs found reasonable in this decision should be adopted.

99. The undisputed portions of PSD's and Edison's joint exhibit on marginal energy costs and Edison's undisputed changes to factors used in the calculation of avoided energy costs should be adopted except as otherwise modified by this decision.

100. The marginal energy costs and avoided energy costs found reasonable in this decision should be adopted.

101. The generation and transmission marginal demand costs found reasonable in this decision should be adopted.

102. To determine the applicability of the ERI for calculating generation marginal demand costs and for determining demand charges used in rate design, Edison and PSD should be directed to examine this issue in Edison's next general rate case.

103. An ERI based on an EUE target should be used as the basis for adjusting the value of the combustion turbine used as a proxy for avoided capacity costs.

104. An ERI adjustment factor of 0.43 should be adopted for 1988 and should remain in effect until updated or revised as prescribed in A.82-04-044, et al.

15. Edison should reflect in A.87-08-054 the level of O&M and refueling expenses found reasonable in this decision for Palo Verde 3.

16. Edison should submit in its next general rate case filing a comparative study that can be used to develop a zone of reasonableness for nuclear O&M expense.

17. Recovery of a one-time expense for a chemical cleaning process at SONGS 3 over three years is reasonable.

18. Recovery of $2.9 million for expenses previously incurred for the reprocessing of spent nuclear fuel from SONGS 1 without Commission approval of the expenses or a tracking mechanism is inappropriate.

19. A test year transmission expense of $75.3 million is reasonable.

20. PSD's $3.5 million reduction to Edison's estimate for account 582 reflects recorded downward trends in labor expense and is reasonable.

21. It is reasonable to reflect Edison's transition to contract labor for tree trimming in account 583.

22. It is reasonable to reflect the accounting change for purchases of meter locking rings in account 597.

23. Edison's estimated cost for its three-year underground inspection program is reasonable.

24. Edison should provide in its next general rate case filing data on the percent of underground switch failures per year and the age of failed switches.

25. A five-year average of storm damages is reasonable.

26. Edison has not provided adequate justification for its estimated cost of providing termination notices to customers.

27. A $450,000 reduction in Edison's estimated cost for providing termination notices to customers is reasonable.

105. The issue of the reinstatement of Standard Offer 2 should be decided in A.82-04-044, et al.

106. Marginal customer costs should be included in the revenue allocation process, should be based on the weighted average of incremental and decremental customer costs, and should include the customer-related costs associated with meters, service drops, final line transformers, access equipment replacement and improvement, and distribution equipment directly assignable to a customer class.

107. In the absence of a "fully developed estimate" of incremental and decremental costs in this proceeding, PSD's incremental cost estimate based on the TSM (transformer, service drop, and meter) approach, exclusive of final line transformers for all customer classes, should serve as the proxy for the weighted average method in this proceeding.

108. In Edison's next general rate case, all parties should base their recommendations of marginal customers costs on the weighted average of Edison's incremental and decremental customer costs.

109. Streetlighting marginal customer costs as calculated by PSD should be included in the revenue allocation process.

110. Edison and PSD should be directed to undertake analyses and record-keeping aimed at identifying all costs to be included as marginal customer costs.

111. The marginal customer costs and marginal distribution costs found reasonable in this decision should be adopted.

112. The marginal cost time-of-use periods found reasonable in this decision should be adopted.

113. A revenue allocation based on an Equal Percent of Marginal Cost (EPMC) approach should be adopted subject, in the test year 1988, to a cap for all customer and rate groups of 5% over the system average percentage change.

114. Because the intent of this decision is to achieve a full EPMC revenue allocation for Edison by 1990, this intent should be

28. Edison's 1986 savings of $225,000 from participation in Enercom should be included in the calculation of its uncollectible rate.

29. An uncollectible rate of .214% and a franchise tax rate of .73% are reasonable.

30. Edison should adjust its annual energy, ECAC, and MAAC rates, effective January 1, 1988, to reflect the uncollectible and franchise tax rates adopted in this decision.

31. Edison should be authorized to reflect an increase in postage expense in its attrition filing.

32. It is reasonable to limit the growth from 1985-1988 in A&G expense items over which Edison has control to 8%, the expected customer growth from 1985-1988.

33. The adopted expense level for account 930 reflects the amortization of expenses due to the abandonment of the Ivanpah project.

34. A 10% reduction in Edison's estimated cost of general insurance, comprehensive general liability insurance, and directors and officers insurance is reflective of market trends and should be adopted.

35. PSD's estimated cost of group life insurance is reasonable.

36. PSD's estimated cost of outside provider medical costs adjusted for employee growth is reasonable.

37. The Superfund Tax should be used as a deduction for calculating income taxes.

38. It is reasonable to reflect the provisions of the Federal Tax Reform Act of 1986 in calculating income taxes.

39. Edison's estimated 1988 plant-in-service is reasonable.

40. The depreciation rates agreed to by Edison and PSD are reasonable.

41. The guidelines for evaluating PHFU are reasonable and should be adopted.

reflected in any revenue allocation proposed for Edison in 1989 and 1990.

115. Edison's ECAC proceeding should be the forum for considering any adjustments of Edison's inter-class revenue allocation in 1989 and 1990, but this consideration should not include the relitigation of the marginal cost structure and levels adopted in this proceeding.

116. For revenue changes occurring between general rate cases, the revenue allocation approach adopted in this proceeding should be applied to rate increases or decreases for the test year 1988 and the revenue allocation approach adopted in Edison's 1989 and 1990 ECAC proceedings should be applied to intervening offset filings made after each of these proceedings.

117. Rate adjustments of less than 1% occurring between general rate cases should be allocated on an equal cents per kWh basis.

118. Intra-class revenue allocation should be developed on an equal percent of present rate revenues for Edison's small and medium power group and on an EPMC basis for Edison's large power customers.

119. Any revenue shortfall resulting from the implementation of new agricultural rate options should be allocated equally among all agricultural rate schedules.

120. Edison should be directed to collect the data necessary to achieve an EPMC revenue allocation for its agricultural and small and medium power customers for its next general rate case.

121. Streetlight energy charges, but not facilities charges associated with an end-use, should be included in the revenue allocation process.

122. In the absence of the adoption of Edison's proposed contract rate schedules, any contract rate revenue deficiency should not be included in the revenue allocation process.

42. The Evaluation and Compliance Division should notify all energy utilities under CPUC jurisdiction that we expect guidelines for evaluating PHFU to be addressed in their next general rate case.

43. Reductions in Edison's estimates of PHFU of $7.5 million for 1988 and $16.2 million for 1989 are reasonable.

44. This proceeding should remain open to consider any changes in the calculation of working cash allowance adopted in A.86-12-050.

45. The method of calculating attrition agreed to by Edison and PSD is reasonable.

46. The 1989 ERAM base level should be increased by $9.8 million to reflect a decrease in FERC sales.

47. Edison should be allowed to include the SONGS 2 chemical cleaning expense in its attrition filing for 1990.

48. The impact of Edison's optional TOU meter plan should be reflected in calculating attrition.

49. Edison should use the format shown in Appendix D to develop its attrition filings.

50. Edison's capital structure as revised in the September update hearings is reasonable.

51. An incremental cost of long-term debt of 9.68% is reasonable.

52. PSD's forecast of tax-exempt financing is reasonable.

53. Edison should be authorized to recover the costs associated with perpetual securities.

54. A ROE of 12.75% is reasonable and should be adopted.

55. Edison's MAAC rates for SONGS 2 and 3 post-commercial operating costs, pre-commercial operating costs for Palo Verde, and Section 463 projects should, effective January 1, 1988, reflect an ROE of 12.75%.

123. The total revenue requirement adopted for Edison as of January 1, 1988, should be included in the revenue allocation adopted in this decision.

124. The rate structures adopted for Edison's rate schedules should reflect, to the extent possible and practical, cost-based rates designed to provide accurate and understandable price signals to which the customer can respond, to reflect a customer's usage patterns and characteristics, to recover the customer group's revenue requirement, and to mitigate any negative bill impacts.

125. The Commission should consider previous recent decisions relating to the rate design of other utilities as a means of identifying current Commission rate design policy; determining whether that policy is to be continued, modified, or abandoned; and ensuring, to the extent possible, consistent treatment of all ratepayers.

126. The baseline quantities and allocations proposed by Edison and PSD should be adopted.

127. Edison's and PSD's requested implementation of a customer charge for domestic customers should be rejected at this time, and Edison's minimum charge for this customer group should be retained.

128. Edison should be directed to undertake a study for its next general rate case to determine the actual line losses incurred by submetered mobilehome parks served under Edison's DMS-2 schedule with the costs of that study being spread equally to all those submetered mobilehome parks.

129. A diversity adjustment should be adopted for all of Edison's domestic master-metered schedules.

130. Edison should be directed to conduct a study for its next general rate case of usage patterns of mobilehome parks which it individual meters and the usage related to each master meter as the basis for developing a diversity adjustment.

131. Edison should be directed to conduct a study for its next general rate case of the need and feasibility of tariff changes

56. Carrying costs on nuclear fuel inventory and coal inventory should be calculated using Edison's ECAC interest rate and recorded in the ECAC account.

57. Recovery of $2.4 million for expenses previously incurred for Palo Verde affirmative case costs without Commission approval of the expenses or a tracking mechanism is inappropriate.

58. Edison should provide, coincident with its fall 1988 resource plan, value-based reliability criteria and a comprehensive study evaluating the range of alternative uses for its aging oil and gas generating units. These should be designed to address PSD's concerns as stated in Exhibit 53.

59. Edison should be authorized to request funding for plant modification or two-shifting to reduce minimum generation capability at certain oil and gas generating units.

60. A cost cap of $91.8 million for Edison's share of the DC Expansion is reasonable.

61. The proposed procedure, attached as Appendix A, which provides for modification of Edison's MAAC to include the recorded investment-related revenue requirement and the recorded revenues related to specific plant additions estimated to cost more than $50 million is reasonable and should be adopted.

62. Edison should be authorized to file for an increase in the MAAC rate, subject to refund, equal to 75% of the annualized investment-related revenue requirement for the DC Expansion, and Devers-Palo Verde projects. Edison's filing should be by an advice letter submitted after each project becomes commercially operational.

63. Edison should file an application to determine the reasonable and prudent costs of the Balsam Meadow, Devers-Valley-Serrano, DC Expansion, and Devers-Palo Verde projects not later than six months after the final portion of each project is placed in-service.

extending baseline allowances or master-metered discounts to RV tenants and RV park owners.

132. Edison should be required to file an advice letter implementing conjunctive billing for schools with multiple meters at a single site on an experimental basis consistent with D.86-12-091 and Resolution E-3045 and to undertake an evaluation for its next general rate case of conjunctive billing for schools and for all customers.

133. Edison and PSD should be directed to develop interruptible schedules for Edison's next general rate case based on both a cost-of service approach and a valuation of curtailability methodology.

134. If necessary, rate limiters should be used to address the problem of adverse bill impacts in order to preserve marginal cost-based rates.

135. The rate structures and charges found reasonable in this decision for each of Edison's rate schedules should be adopted.

136. PSD's proposed rate design for revenue requirement changes occurring between general rate cases based on increasing demand and customer charges toward their EPMC relationships for revenue requirement increases and holding them constant for decreases should be adopted.

137. Revenue changes between general rate cases attributable to energy charges should be reflected in that rate component.

INTERIM ORDER

IT IS ORDERED that:

1. Southern California Edison Company (Edison) is authorized and directed to file with this Commission, on or after the effective date of this order, and at least 3 days prior to their effective date, revised tariff schedules for electric rates as set forth in Appendix I.

64. Edison's MAAC revenue requirement should be increased by $73.7 million for Devers-Valley-Serrano and Balsam Meadow and the MAAC rate should be increased by $55.3 million or 0.085 cents/kWh, subject to refund.

65. PSD's motion to set aside submission of the DC Expansion project should be denied.

66. Edison failed to disclose the existence of a letter agreement with LADWP, that could impact the cost-effectiveness analysis of the DC Expansion project and link it with other transmission projects.

67. PSD's motion to compel the production of the documents, attachment 6 to the motion, should be granted.

68. The cost-effectiveness analysis of the DC Expansion project and the adopted cap should be reviewed in conjunction with our analysis of Edison's other transmission projects and/or the agreements with LADWP.

69. In order to insure consistent ratemaking treatment, SDG&E's portion of SONGS O&M expenses billed to it by Edison should be reflected in future SDG&E base rate changes at the level adopted by this order adjusted for inflation.

70. Edison's requested funding for the competing for the customer RD&D program is reasonable.

71. Edison's requested funding for the electric transportation RD&D project should be reduced to $100,000 for monitoring the work of others.

72. Edison should be authorized to spend $900,000 on its alternate fuels, occupational and community safety, and advanced energy conversion RD&D programs.

73. Edison's natural resources management RD&D program should not be funded.

74. Edison's actual 1988 EPRI dues of $14.7 million should be authorized in rates.

2. The revised tariff schedules shall become effective on or after January 1, 1988 and shall comply with General Order 96-A. The revised tariffs shall apply to service rendered on or after their effective date.

3. All transcript corrections received are incorporated in the record.

4. Edison is authorized to file for an attrition adjustment in 1989 and 1990 based on the results of operation adopted in Appendix C and D.

5. Edison is authorized to include in its attrition filings increases in postage expenses and Nuclear Regulatory Commission fees.

6. Edison shall adjust its ERAM effective January 1, 1989 to reflect full implementation of the guidelines for plant held for future use contained in Appendix B. The guidelines shall apply to all plant held for future use regardless of the acquisition date.

7. Edison is authorized to increase its MAAC revenue requirement by $26.0 million and its MAAC rate by $19.5 million or 0.030 cents/kWh, subject to refund, for the Devers-Valley-Serrano project.

8. Within six months from the date of this order Edison shall file an application to establish the reasonable and prudent level of recorded costs of the Devers-Valley-Serrano project.

9. The procedures set forth in Appendix A for proposed projects in excess of $50 million are reasonable and shall be adopted.

10. Edison is authorized to file for MAAC increases, subject to refund, for the Balsam Meadows, DC Expansion, and Devers-Palo Verde project in accordance with the adopted procedures in Appendix A.

11. A.86-12-047 shall remain open to consider the impact of a final decision on working cash allowance in A.85-12-050.

75. Edison should emphasize long-term, end-use RD&D that is consistent with its resource plan and coordinated with other California utilities and experienced research organizations.

76. Edison should work with the Institute in resolving any difficulties surrounding Edison's competitive bidding policies for RD&D.

77. All RD&D program expenditures should be recorded in account 930.2.

78. A one-way balancing account for RD&D expenditures should be adopted.

79. All expenditures on RD&D program changes should be removed from the one-way balancing account, retroactively, if found unreasonable in a subsequent proceeding.

80. A productivity gain of approximately 2.75% for 1988 is reasonable.

81. Edison and PSD should jointly develop a data base for use in evaluating employee compensation in Edison's next general rate case.

82. Edison's and PSD's agreement on ratemaking treatment for gains on sales of utility assets to affiliates, net income of utility-related subsidiaries, markup royalty for services provided by the utility, and guidelines for utility employee transfers to affiliates is reasonable and should be adopted.

83. PSD's recommended royalty to be paid by affiliates on gross revenues should not be considered in this decision.

84. PSD's hazardous waste management recommendations are reasonable and should be adopted as modified below.

85. PSD's recommendations concerning manufactured gas hazardous waste sites should be expanded to include all hazardous waste sites included in Edison's general rate case filing and/or its annual hazardous waste management report.

12. The Commission's Evaluation and Compliance Division shall notify the energy utilities we regulate that guidelines for evaluating plant held for future use shall be considered in their next general rate case.

13. Edison shall file as set forth in this order an annual report describing its hazardous waste effort, including its underground storage program. The report shall include the information described in Exhibit 65-A.

14. Edison is authorized to file an application(s) as discussed in this order to receive prior approval for funding its hazardous waste program.

15. Edison is authorized to file for funding plant modifications or two-shifting to reduce its minimum generation capability.

16. Coincident with its fall 1988 resource plan, Edison shall provide value-based reliability criteria and a comprehensive study evaluating the range of alternative uses for its aging oil and gas generating units.

17. Edison is authorized and directed to reflect the adopted return on equity from this order in its MAAC revenue requirement.

18. Edison is authorized and directed to reflect the adopted franchise tax and uncollectible rates from this order in its MAAC, ECAC, and AER rates.

19. Edison is authorized to reflect in its ECAC account the carrying costs associated with nuclear fuel inventory and coal inventory, based on the ECAC interest rate.

20. SDG&E is authorized to reflect in future base rate filings the level of O&M expenses for SONGS adopted by this order.

21. Edison shall establish a one-way balancing account for recording RD&D expenditures.

22. Edison and PSD shall jointly develop a data base for use in evaluating employee compensation in Edison's next general rate case.

86. Edison should be allowed to combine the two different annual hazardous waste reports PSD recommends into one annual report.

87. Long-term goal setting, verification procedures, and annual reporting for utility F/MBE programs should be addressed in R.87-02-026.

88. Edison had a significant increase in the amount and number of its contract awards to F/MBEs from 1984-1986.

89. Edison should achieve significant increases in the amount and number of contract awards to F/MBEs for future proceedings.

90. Ethics and fairness dictate that an extension to file a brief granted to one, but not all, parties to a proceeding should not be used as an opportunity to respond to briefs which were timely filed.

91. Edison should continue to promote reasonable and cost-effective conservation measures and efficiency options for its customers.

92. To ensure its continued cost-effectiveness, Edison should closely monitor its Thermal Energy Storage program in coming years through the reporting requirements established in Resolution E-3053 and the establishment, for accounting and reporting purposes, of the categories of Load Shifting (Medium/Small and Large Customer) and Load Retention (Medium/Small and Large Customer).

93. Edison should be directed to continue its efforts to quantify the gas-side impacts of its Thermal Energy Storage program consistent with the recently reused Standard Practice Manual for Economic Evaluation of DSM Programs.

94. To ensure the continued cost-effectiveness of its Water Storage Program, Edison should undertake whatever reasonable cost-cutting measures are possible to limit any unnecessary and non-cost-effective spending.

23. Edison shall continue to closely monitor its Thermal Energy Storage Program by meeting the reporting requirements established in Resolution E-3053 and the establishment, for accounting and reporting purposes of the categories of Load Shifting (Medium/Small and Large Customer) and Load Retention (Medium/Small and Large Customer) and shall continue its efforts to quantify the gas-side impacts of this program.

24. Edison is authorized to offer an incentive under its Thermal Energy Storage program limited to $200/kW.

25. Edison's shall develop the reports required for its demand side management programs using the same guidelines adopted for the Pacific Gas and Electric Company (PG&E) in D.86-12-095.

26. Edison shall use PSD's uniform program definitions for demand side management programs in all future rate case, offset, and advice letter filings.

27. Edison is authorized to consolidate all demand side management program funding in base rates beginning with test year 1988.

28. Edison is authorized to make funding shifts of $2.5 million within the three major demand side management categories (Residential Conservation, Commercial/Industrial/Agricultural Conservation, and Load Management) without an advice letter, but with notice of the change to the Commission's Evaluation and Compliance Division.

29. Edison shall file an advice letter for funding shifts between the three major demand side management categories or for shifts of greater than $2.5 million within those categories.

30. Periodic analysis on the optimal funding of Edison's Cogeneration/Small Power Production Program shall be undertaken by PSD and Edison, with the first report to be completed on August 31, 1988, to determine whether reductions in program funding of $200,000 in 1989 and $550,000 in 1990 are warranted.

95. Funding for Edison's Residential and Non-Residential Marketing programs should be deferred until further analysis of the marketing issue is undertaken in the 3-Rs Rulemaking, R.86-10-001.

96. Edison should develop the reports required for its demand side management programs using the same guidelines adopted for PG&E in D.86-12-095 at pages 111 through 118.

97. The generic demand side management definitions being established in the Reporting Requirements Manual should be used by Edison in all future rate case, offset, and advice letter filings.

98. The funding levels found reasonable in this decision for Edison's demand side management programs should be adopted with an overall funding level of $54,194,000.

99. All demand side management program funding should be consolidated and placed in base rates starting with the test year 1988, with the exception of certain TES incentive payments as described in our discussion.

100. Edison should continue to be allowed to make funding shifts of $2.5 million within the three major demand side management categories without an advice letter, but with notice to the Commission's Evaluation and Compliance Division.

101. Edison should be required to file an advice letter for funding shifts between the three major demand side management program categories or for shifts of greater than $2.5 million within those categories.

102. Edison should continue the effective development of QF resources.

103. The overall funding for Edison's Cogeneration/Small Power Production Program of $1,765,000, with reductions of $200,000 in 1989 and $550,000 in 1990, if warranted on the basis of a periodic analysis to be undertaken by Edison and PSD, found reasonable in this proceeding should be adopted.

104. The results of operation as set forth in Appendixes C and D are reasonable and should be adopted.

31. All parties to the future general rate case and ECAC proceedings of Edison, PG&E, and San Diego Gas and Electric Compan (SDG&E) presenting testimony relying or or requiring the use of a production simulation model to develop marginal or avoided costs shall provide a "base case" run using the ELFIN production cost model. A party to these proceedings may also present testimony using its production cost model of choice, which may differ from ELFIN, and explain the basis for its preference of that model and the results which it produces.

32. In the future rate case and ECAC proceedings of Edison, PG&E, and SDG&E, workshops shall be held no later than one week following the filing of the utility's testimony in those proceedings. The purpose of this workshop shall be to determine the data sets, resource plans, load shape, heat rate input,unit commitment and dispatch, minimum load conditions, resource assumptions, marginal fuel assumptions, and all other pertinent data which the utility used to calculate its Incremental Energy Rate (IER). In addition to data gathering, this workshop shall also serve as a forum in which the parties can agree, to the extent possible, on the assumptions to be used and the appropriate source of those assumptions.

33. Edison and PSD shall present testimony in Edison's next general rate case on the applicability of the ERI to calculations of generation marginal demand costs and to determinations of demand charges used in rate design.

34. For Edison's next general rate case, all parties shall base their recommendations of marginal customer costs on the weighted average of Edison's incremental and decremental customer costs.

35. With respect to the determination of marginal customer costs, Edison and PSD shall undertake the following for Edison's next general rate case: (1) establish record-keeping that will clearly identify customer hook-up costs and distinguish new from

105. Based on the foregoing findings and conclusions a $57.7 million decrease in Edison's base rate revenues is just and reasonable and should be adopted.

106. The Commission's findings in this general rate case on issues related to marginal cost, revenue allocation, rate design, and demand side management programs should take into consideration the policies adopted in R.86-10-001 to address the problem of uneconomic bypass.

107. Marginal costs should continue to be the basis for the revenue allocation and rate design adopted in this proceeding.

108. In the future general rate cases, ECAC proceedings, or other proceeding designated by A.82-04-44, et al., of Edison, PG&E, and SDG&E, all parties presenting testimony requiring the use of a production simulation model to develop marginal or avoided costs should provide a "base case" run using the ELFIN model.

109. To ensure access by all parties to input assumptions and data related to cumputer models used to calculate a utility's IERs, a workshop should be held no later than one week following the filing of testimony by either Edison, PG&E, or SDG&E in their respective ECACs, general rate case proceedings, or other proceeding designated by A.82-04-44, et al. for updating IERs.

110. The purpose of the workshop referenced in the preceding conclusion should be (1) to determine the data sets, resource plans, load shape, heat rate input, unit commitment and dispatch, minimum load conditions, resource assumptions, marginal fuel assumptions, and all other pertinent data which the utility has used to calculate its IER and (2) to provide a forum in which agreements between the parties can be reached.

111. Two IERs should be adopted in this proceeding, one for use in the calculation of marginal energy costs and one for use in the calculation of avoided energy costs, based on methodologies which reflect the differences in these two costs.

existing customers, (2) analyze non-dedicated distribution equipment for access versus demand function, and (3) identify replacement and upgrading costs for access equipment.

36. Edison's ECAC proceeding shall be the forum for considering any adjustments of Edison's inter-class Equal Percent of Marginal Cost (EPMC) revenue allocation in 1989 and 1990. This consideration shall not include the relitigation of the marginal cost structure and levels adopted in this proceeding.

37. For rate changes occurring between this rate case and Edison's 1989 ECAC proceeding, the revenue allocation approach adopted in this proceeding based on an EPMC allocation with a 5% cap over the system average percentage change shall be applied to the intervening rate increases or decreases. The revenue allocation approach adopted in Edison's ECAC proceedings for the 1989 and 1990 periods shall be applied to Edison's intervening offset filings made after each of those proceedings.

38. For its next general rate case, Edison shall collected the data necessary to achieve an intra-class EPMC revenue allocation for Edison's small light and power and agricultural rate schedules.

39. Edison shall undertake a study for its next general rate case to determine the actual line losses incurred by submetered mobilehome parks served under Edison's DMS-2 schedule. The costs of that study shall be spread equally to all those submetered mobilehome park customers.

40. Edison shall conduct a study for its next general rate case of usage patterns of its domestic master-metered customers which it individually meters as the basis for developing a diversity adjustment of the submetered discount or rates applicable to those customers.

41. Edison shall conduct a study for its next general rate case of the need and feasibility of tariff changes extending baseline allowances or master-metered discounts to recreational

112. The annual IERs found reasonable in this decision should be adopted and should remain in effect until updated as prescribed in A.82-04-44 et al.

113. In the calculation of IERs, the adjustment of the ELFIN model to reflect start-up and no-load costs should be reduced in the amount of any double-counting of these costs.

114. The input assumptions used in calculating marginal and avoided energy costs found reasonable in this decision should be adopted.

115. The undisputed portions of PSD's and Edison's joint exhibit on marginal energy costs and Edison's undisputed changes to factors used in the calculation of avoided energy costs should be adopted except as otherwise modified by this decision.

116. The marginal energy costs and avoided energy costs found reasonable in this decision should be adopted.

117. The generation and transmission marginal demand costs found reasonable in this decision should be adopted.

118. To determine the applicability of the ERI for calculating generation marginal demand costs and for determining demand charges used in rate design, Edison and PSD should be directed to examine this issue in Edison's next general rate case.

119. An ERI based on an EUE target should be used as the basis for adjusting the value of the combustion turbine used as a proxy for avoided capacity costs.

120. An ERI adjustment factor of 0.43 should be adopted for 1988 and should remain in effect until updated or revised as prescribed in A.82-04-44, et al.

121. The issue of the reinstatement of Standard Offer 2 should be decided in A.82-04-44, et al.

122. Marginal customer costs should be included in the revenue allocation process, should be based on the weighted average of incremental and decremental customer costs, and should include the customer-related costs associated with meters, service drops, final

vehicle (RV) tenants and RV park owners. This study should include an examination of the tariff language needed to ensure that RV "residents" receive the baseline allowances to which they are entitled. Any standards proposed by Edison should take into account Edison's ability to objectively judge and realistically monitor the status of the RV tenant.

42. Edison shall file an advice letter implementing conjunctive billing for schools with multiple meters at a single site on an experimental basis. This filing shall provide tariffs or forms based consistent with D.86-12-091 and Resolution E-3045 in which PG&E was authorized to offer conjunctive billing to schools. Edison shall also conduct a study for its next general rate case evaluating conjunctive billing for schools and for all customers.

43. Edison and PSD shall propose interruptible schedules for Edison's next general rate case based on both a cost-of-service approach and a valuation of curtailibility methodology.

44. For rate changes between general rate cases, demand and customer charges shall be increased based on their EPMC relationships for rate increases, but shall be held constant for rate decreases. Revenue changes between general rate cases atrributable to energy charges shall be reflected in that rate component.

This order is effective today.

Dated ______________, at San Francisco, California.

line transformers, access equipment replacement and improvement, and distribution equipment directly assignable to a customer class.

123. In the absence of a "fully developed estimate" of incremental and decremental costs in this proceeding, PSD's incremental cost estimate based on the TSM (transformer, service drop, and meter) approach, exclusive of final line transformers for all customer classes, should serve as the proxy for the weighted average method in this proceeding.

124. In future general rate cases, all parties should base their recommendations and numerical estimates of marginal customers costs on the weighted average of the utility's incremental and decremental customer costs.

125. Streetlighting marginal customer costs as calculated by PSD should be included in the revenue allocation process.

126. Edison and PSD should be directed to undertake analyses and record-keeping aimed at identifying all costs to be included as marginal customer costs.

127. The marginal customer costs and marginal distribution costs found reasonable in this decision should be adopted.

128. The marginal cost time-of-use periods found reasonable in this decision should be adopted.

129. A revenue allocation based on an Equal Percent of Marginal Cost (EPMC) approach should be adopted based on moving 1/3 of the way to EPMC in the test year 1988, with a cap for all customer and rate groups of 5% on increases over the system average percentage change.

130. Because the intent of this decision is to achieve a full EPMC revenue allocation for Edison by 1990, this intent should be reflected in any revenue allocation proposed for Edison in 1989 and 1990.

131. Edison's ECAC proceeding should be the forum for considering any adjustments of Edison's inter-class revenue allocation in 1989 and 1990, but this consideration should not

include the relitigation of the marginal cost structure and levels adopted in this proceeding.

132. For revenue changes occurring between general rate cases, a system average percentage change revenue allocation approach should be applied to rate increases or decreases occurring between this rate case and Edison's 1989 ECAC, with the revenue allocation for intervening offset filings made after that time to be determined in Edison's 1989 and 1990 ECAC proceedings.

133. Rate adjustments of less than 1% occurring between general rate cases should be allocated on an equal cents per kWh basis.

134. Intra-class revenue allocation should be developed on an equal percent of present rate revenues for Edison's small and medium power group, except for TOU-GS and GS-2 which should be based on PSD's and Edison's agreed billing determinants, and on an EPMC basis for Edison's large power customers.

135. Any revenue shortfall resulting from the implementation of new agricultural rate options should be allocated equally among all agricultural rate schedules.

136. Edison should be directed to collect the data necessary to achieve an EPMC revenue allocation for its agricultural and small and medium power customers for its next general rate case.

137. Streetlight energy charges, but not facilities charges associated with an end-use, should be included in the revenue allocation process.

138. Any contract rate revenue deficiency should not be included in the revenue allocation process.

139. The total revenue requirement adopted for Edison as of January 1, 1988, should be included in the revenue allocation adopted in this decision.

140 The rate structures adopted for Edison's rate schedules should reflect, to the extent possible and practical, cost-based rates designed to provide accurate and understandable price signals

to which the customer can respond, to reflect a customer's usage patterns and characteristics, to recover the customer group's revenue requirement, and to mitigate any negative bill impacts.

141. The Commission should consider previous recent decisions relating to the rate design of other utilities as a means of identifying current Commission rate design policy; determining whether that policy is to be continued, modified, or abandoned; and ensuring, to the extent possible, consistent treatment of all ratepayers.

142. The baseline quantities and allocations proposed by Edison and PSD should be adopted.

143. Edison's and PSD's requested implementation of a customer charge for domestic customers should be rejected at this time, and Edison's minimum charge for this customer group should be retained.

144. Edison should be directed to undertake a study, in cooperation with WMA, for its next general rate case to determine the actual line losses incurred by submetered mobilehome parks served under Edison's DMS-2 schedule.

145. A diversity adjustment should be adopted for all of Edison's domestic master-metered schedules.

146. Edison should be directed to conduct a study for its next general rate case of usage patterns of mobilehome parks which it individual meters and the usage related to each master meter as the basis for developing a diversity adjustment.

147. Edison should be directed to conduct a study for its next general rate case of the need and feasibility of tariff changes extending baseline allowances or master-metered discounts to RV tenants and RV park owners.

148. Edison should be required to file an advice letter implementing conjunctive billing for schools with multiple meters at a single site on an experimental basis consistent with D.86-12-091 and Resolution E-3045 and to undertake an evaluation

for its next general rate case of conjunctive billing for schools and for all customers.

149. Edison and PSD should be directed to develop interruptible schedules for Edison's next general rate case based on both a cost-of service approach and a valuation of curtailability methodology.

150. If necessary, rate limiters should be used to address the problem of adverse bill impacts in order to preserve marginal cost-based rates.

151. Edison should be directed to conduct, in cooperation with PSD, a workshop to explain and seek refinements to the new agricultural rate options adopted in this decision.

152. The rate structures and charges found reasonable in this decision for each of Edison's rate schedules should be adopted.

153. PSD's proposed rate design for revenue requirement changes occurring between general rate cases based on increasing demand and customer charges toward their EPMC relationships for revenue requirement increases and holding them constant for decreases should be adopted.

154. The TOU-D tariff option and the new agricultural tariff options should be implemented by Edison no later than June 1, 1988.

155. The increases in rates and charges authorized by this decision are justified, and are just and reasonable.

INTERIM ORDER

IT IS ORDERED that:

1. Southern California Edison Company (Edison) is authorized and directed to file with this Commission, on or after the effective date of this order, and at least 3 days prior to their effective date, revised tariff schedules for electric rates as set forth in Appendix I.

2. The revised tariff schedules shall become effective on or after January 1, 1988 and shall comply with General Order 96-A. The revised tariffs shall apply to service rendered on or after their effective date.

3. All transcript corrections received are incorporated in the record.

4. Edison is authorized to file attrition adjustments for 1989 and 1990 based on the results of operation adopted in Appendix C and D.

5. Edison shall provide in its next general rate case filing data on the percent of underground switch failures per year and the age of failed switches.

6. Edison is authorized to include in its attrition filings increases in postage expenses and Nuclear Regulatory Commission fees.

7. Edison shall adjust its ERAM effective January 1, 1989 to reflect full implementation of the guidelines for plant held for future use contained in Appendix B. The guidelines shall apply to all plant held for future use regardless of the acquisition date.

8. Edison is authorized to increase its MAAC revenue requirement by $73.7 million and its MAAC rate by $55.3 million or 0.085 cents/kWh, subject to refund, for the Devers-Valley-Serrano and Balsam Meadow projects.

9. Within six months from the date of this order Edison shall file an application to establish the reasonable and prudent

level of recorded costs of the Devers-Valley-Serrano and Balsam Meadow projects.

10. The procedures set forth in Appendix A for proposed projects in excess of $50 million are reasonable and shall be adopted.

11. Edison is authorized to file for MAAC increases, subject to refund, for the DC Expansion and Devers-Palo Verde projects in accordance with the adopted procedures in Appendix A.

12. Edison shall produce the documents requested by PSD in attachment 6 to its motion within 10 days from the effective date of this decision.

13. A.86-12-047 shall remain open to consider the impact of a final decision on working cash allowance in A.85-12-050.

14. The Commission's Evaluation and Compliance Division shall notify the energy utilities we regulate that guidelines for evaluating plant held for future use shall be considered in their next general rate case.

15. Edison shall file as set forth in this order an annual report describing its hazardous waste effort, including its underground storage program. The report shall include the information described in Exhibit 65-A.

16. Edison is authorized to file an application(s) as discussed in this order to receive prior approval for funding its hazardous waste program.

17. Edison is authorized to file for funding plant modifications or two-shifting to reduce its minimum generation capability.

18. Coincident with its fall 1988 resource plan, Edison shall provide value-based reliability criteria and a comprehensive study evaluating the range of alternative uses for its aging oil and gas generating units.

19. Edison is authorized and directed to reflect the adopted return on equity from this order in its MAAC revenue requirement, effective January 1, 1988.

20. Edison is authorized and directed to reflect the adopted franchise tax and uncollectible rates from this order in its MAAC, ECAC, and AER rates, effective January 1, 1988.

21. Edison is authorized to reflect in its ECAC account the carrying costs associated with nuclear fuel inventory and coal inventory, based on the ECAC interest rate.

22. SDG&E is authorized to reflect in future base rate filings the level of O&M expenses for SONGS, adjusted for inflation, adopted by this order.

23. Edison shall provide a comparative study in its next general rate case filing which establishes a zone of reasonableness for nuclear O&M expense.

24. Edison shall establish a one-way balancing account for recording RD&D expenditures.

25. Edison and PSD shall jointly develop a data base for use in evaluating employee compensation in Edison's next general rate case.

26. Edison shall continue to closely monitor its Thermal Energy Storage Program by meeting the reporting requirements established in Resolution E-3053 and the establishment, for accounting and reporting purposes of the categories of Load Shifting (Medium/Small and Large Customer) and Load Retention (Medium/Small and Large Customer) and shall continue its efforts to quantify the gas-side impacts of this program consistent with the recently reused Standard Practice Manual for Economic Evaluation of Demand Side Management Programs.

27. Edison is authorized to offer an incentive under its Thermal Energy Storage program limited to $200/kW.

28. Edison's shall develop the reports required for its demand side management programs using the same guidelines adopted

for the Pacific Gas and Electric Company (PG&E) in D.86-12-095 and the Reporting Requirements Manual being developed in response to that order.

29. Edison shall use the generic demand side management definitions being established in the Reporting Requirements Manual in all future rate case, offset, and advice letter filings.

30. Edison is authorized to consolidate all demand side management program funding in base rates beginning with test year 1988 with the exception that all TES incentive payments related to contracts executed prior to January 1, 1988, shall continue to be reflected in the ERAM balancing account consistent with D.82-12-055.

31. Edison is authorized to make funding shifts of $2.5 million within the three major demand side management categories (Residential Conservation, Commercial/Industrial/Agricultural Conservation, and Load Management) without an advice letter, but with notice of the change to the Commission's Evaluation and Compliance Division.

32. Edison shall file an advice letter for funding shifts between the three major demand side management categories or for shifts of greater than $2.5 million within those categories.

33. Periodic analysis on the optimal funding of Edison's Cogeneration/Small Power Production Program shall be undertaken by PSD and Edison, with the first report to be completed on August 31, 1988, to determine whether reductions in program funding of $200,000 in 1989 and $550,000 in 1990 are warranted.

34. All parties to the future general rate cases, ECAC proceedings, or other related proceeding identified in A.82-04-44, et al., of Edison, PG&E, and San Diego Gas and Electric Company (SDG&E) presenting testimony relying on or requiring the use of a production simulation model to develop marginal or avoided costs shall provide a "base case" run using the ELFIN production cost model. A party to these proceedings may also present testimony

using its production cost model of choice, which may differ from ELFIN, and explain the basis for its preference of that model and the results which it produces.

35. In the future general rate cases, ECAC proceedings, or other related proceeding identified in A.82-04-44, et al., of Edison, PG&E, and SDG&E, workshops shall be held no later than one week following the filing of the utility's testimony in those proceedings. The purpose of this workshop shall be to determine the data sets, resource plans, load shape, heat rate input, unit commitment and dispatch, minimum load conditions, resource assumptions, marginal fuel assumptions, and all other pertinent data which the utility used to calculate its Incremental Energy Rate (IER). In addition to data gathering, this workshop shall also serve as a forum in which the parties can agree, to the extent possible, on the assumptions to be used and the appropriate source of those assumptions. The Director of the Commission's Advisory and Compliance Division shall appoint a final arbiter of disputes relating to the achievement of a common data set.

36. Edison and PSD shall present testimony in Edison's next general rate case on the applicability of the ERI to calculations of generation marginal demand costs and to determinations of demand charges used in rate design.

37. For the general rate cases of each electric utility, all parties shall base their recommendations and numerical estimates of marginal customer costs on the weighted average of the utility's incremental and decremental customer costs.

38. With respect to the determination of marginal customer costs, Edison and PSD shall undertake the following for Edison's next general rate case: (1) establish record-keeping that will clearly identify customer hook-up costs and distinguish new from existing customers, (2) analyze non-dedicated distribution equipment for access versus demand function, and (3) identify replacement and upgrading costs for access equipment.

39. Edison's ECAC proceeding shall be the forum for considering any adjustments of Edison's inter-class Equal Percent of Marginal Cost (EPMC) revenue allocation in 1989 and 1990. This consideration shall not include the relitigation of the marginal cost structure and levels adopted in this proceeding.

40. For rate changes occurring between this rate case and Edison's 1989 ECAC proceeding, Edison's rate schedules shall be changed by the system average percentage change to maintain the relationships adopted in this proceeding. The revenue allocation approach to be applied to Edison's intervening offset filings made after Edison's ECAC proceedings for the 1989 and 1990 periods shall be identified in those proceedings.

41. For its next general rate case, Edison shall collect the data necessary to achieve an intra-class EPMC revenue allocation for Edison's small light and power and agricultural rate schedules.

42. Edison shall undertake, in cooperation with WMA, a study for its next general rate case to determine the actual line losses incurred by submetered mobilehome parks served under Edison's DMS-2 schedule.

43. Edison shall conduct a study for its next general rate case of usage patterns of its domestic master-metered customers which it individually meters as the basis for developing a diversity adjustment of the submetered discount or rates applicable to those customers.

44. Edison shall conduct a study for its next general rate case of the need and feasibility of tariff changes extending baseline allowances or master-metered discounts to recreational vehicle (RV) tenants and RV park owners. Any standards proposed by Edison should take into account Edison's ability to objectively judge and realistically monitor the status of the RV tenant.

45. Edison shall file an advice letter implementing conjunctive billing for schools with multiple meters at a single site on an experimental basis. This filing shall provide tariffs

or forms based consistent with D.86-12-091 and Resolution E-3045 in which PG&E was authorized to offer conjunctive billing to schools. Edison shall also conduct a study for its next general rate case evaluating conjunctive billing for schools and for all customers.

46. Edison and PSD shall propose interruptible schedules for Edison's next general rate case based on both a cost-of-service approach and a valuation of curtailibility methodology.

47. The Commission shall direct, at a date to be set, that a workshop be held by Edison, in cooperation with PSD, to explain and consider refinements to the new agricultural tariff options adopted in this order.

48. For rate changes between general rate cases, demand and customer charges shall be increased based on their EPMC relationships for rate increases, but shall be held constant for rate decreases.

This order is effective today.

Dated DEC 22 1987, at San Francisco, California.

STANLEY W. HULETT
President
DONALD VIAL
FREDERICK R. DUDA
G. MITCHELL WILK
JOHN B. OHANIAN
Commissioners

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
OPERATING REVENUES AT PRESENT RATES
Thousands Of 1988 Dollars
Test Year 1988

Description	Adopted
Domestic	$895,665
Lighting-Sm & Med Power	972,160
Large Power	645,303
Agricultural & Pumping	77,901
Street & Area Lighting	53,607
Five Customer Groups and Santa Catalina Island	$2,644,636
TOU-Resale	64,639
Sequoia	13
Fringe	0
Net Edison	$2,709,288
SWP	0
MWD	7
Resale - Special	6,679
Subtotal	2,715,974
Other Operating Revenues	$51,416
Total Operating Revenues	$2,767,390

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
CALCULATION OF FRANCHISE FEES AND UNCOLLECTIBLES
Thousands Of 1988 Dollars
Test Year 1988

Description	Adopted
At Present Rates	
Revenues at Current Rates	$2,644,636
Uncollectible Factor	0.00214
Uncollectibles	$5,660
Revenues From Customers	$2,715,974
Franchise Requirement Factor	0.0073
Total Franchise Requirements	$19,827

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
TOTAL PRODUCTION EXPENSE
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Description	Adopted
Operation	
Steam	$72,608
Nuclear	91,037
Hydraulic	8,550
Other	8,356
Total Operation	$180,551
Maintenance	
Steam	136,645
Nuclear	76,422
Hydraulic	11,922
Other	8,869
Total Maintenance	$233,858
TOTAL PRODUCTION (1985$)	$414,410
Escalation Amounts, 1985 to 1988	
Labor	17,053
Non-Labor	24,078
Other	0
Total	$41,131
TOTAL PRODUCTION (1988$)	$455,540

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
STEAM PRODUCTION EXPENSE
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Account No.	Description	Adopted
	Operation	
500.0	Supervision and Engineering	$7,431
501.0	Fuel Related Expenses	25,080
502.0	Steam Expenses	14,091
505.0	Electric Expenses	6,856
506.0	Misc. Steam Power Expenses	18,975
507.0	Rents	175
	Total Operation	$72,608
	Maintenance	
510.0	Supervision and Engineering	19,480
511.0	Structures	6,736
512.0	Boiler Plant	66,818
513.0	Electric Plant	35,181
514.0	Miscellaneous Steam Plant	8,430
	Total Maintenance	$136,645
	TOTAL STEAM PRODUCTION (1985$)	$209,254
	Escalation Amounts, 1985 to 1988	
	Labor	7,083
	Non-Labor	13,164
	Other	0
	Total	$20,247
	TOTAL STEAM PRODUCTION (1988$)	$229,500

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
NUCLEAR PRODUCTION EXPENSE excl. PALO VERDE UNIT #3
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Account No.	Description	Adopted
	Operation	
517.0	Supervision and Engineering	$32,440
519.0	Coolants and Water	5,977
520.0	Steam Expenses	12,258
523.0	Electric Expenses	1,923
524.0	Misc. Nuclear Power Expenses	37,969
525.0	Rents	470
	Total Operation	$91,037
	Maintenance	
528.0	Supervision and Engineering	25,168
529.0	Structures	8,448
530.0	Reactor Plant Equipment	18,195
531.0	Electric Plant	11,176
532.0	Miscellaneous Nuclear Plant	13,435
	Total Maintenance	$76,422
	TOTAL NUCLEAR PROD. (1985$)	$167,459
	Escalation Amounts, 1985 to 1988	
	Labor	8,098
	Non-Labor	8,901
	Other	0
	Total	$16,999
	TOTAL NUCLEAR PROD. (1988$)	$184,458

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
HYDRAULIC PRODUCTION EXPENSE
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Account No.	Description	Adopted
	Operation	
535.0	Supervision and Engineering	$1,783
536.0	Water for Power	1,309
537.0	Hydraulic Expenses	2,104
538.0	Electric Expense	1,840
539.0	Misc. Hydro Expense Generation	1,311
540.0	Rents	203
	Total Operation	$8,550
	Maintenance	
541.0	Supervision and Engineering	1,099
542.0	Structures	1,102
543.0	Reservoirs, Dams and Waterways	2,069
544.0	Maintenance of Electric Plant	5,930
545.0	Miscellaneous Hydraulic Plant	1,722
	Total Maintenance	$11,922
	TOTAL HYDRO PRODUCTION (1985$)	$20,472
	Escalation Amounts, 1985 to 1988	
	Labor	1,073
	Non-Labor	1,047
	Other	0
	Total	$2,120
	TOTAL HYDRO PRODUCTION (1988$)	$22,592

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
OTHER POWER PRODUCTION EXPENSE
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Account No.	Description	Adopted
	Operation	
546.0	Supervision and Engineering	$979
548.0	Generation Expenses	2,489
549.0	Misc. Other Power Expenses	4,856
550.0	Rents	32
	Total Operation	$8,356
	Maintenance	
551.0	Supervision and Engineering	912
552.0	Maintenance of Structures	619
553.0	Maintenance of Electric Plant	6,792
554.0	Misc. Other Power Gen. Plant	546
	Total Maintenance	$8,869
	TOTAL OTHER PRODUCTION (1985$)	$17,225
	Escalation Amounts, 1985 to 1988	
	Labor	799
	Non-Labor	966
	Other	0
	Total	$1,765
	TOTAL OTHER PRODUCTION (1988$)	$18,990

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
TRANSMISSION EXPENSE
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Account No.	Description	Adopted
	Operation	
560.0	Supervision and Engineering	$7,034
561.0	Load Dispatching	3,081
562.0	Station Expenses	14,766
563.0	Overhead Line Expenses	1,135
564.0	Underground Line Expenses	32
565.0	Trans. of Elect. By Others	15,033
566.0	Misc. Transmission Expenses	3,742
567.0	Rents	529
	Total Operation	$45,352
	Maintenance	
568.00	Supervision and Engineering	4,179
569.00	Structures	2,059
570.00	Station Equipment	8,872
571.00	Overhead Lines	10,869
572.00	Underground Lines	94
573.00	Misc. Transmission Plant	3,918
	Total Maintenance	$29,991
	TOTAL TRANSMISSION (1985$)	$75,343
	Escalation Amounts, 1985 to 1988	
	Labor	4,014
	Non-Labor	2,362
	Other	0
	Total	$6,376
	TOTAL TRANSMISSION (1988$)	$81,719

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
DISTRIBUTION EXPENSE
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Account No.	Description	Adopted
	Operation	
580.0	Supervision and Engineering	$16,482
582.0	Station Expenses	8,592
583.0	Overhead Line Expenses	5,508
584.0	Underground Line Expenses	5,476
585.0	Street Lighting & Signal Sys.	1,196
586.0	Meter Expenses	11,567
587.0	Customer Installations	10,093
588.0	Misc. Distribution Expenses	17,229
589.0	Rents	1,188
	Total Operation	$77,331
	Maintenance	
590.00	Supervision and Engineering	9,004
591.00	Structures	4,071
592.00	Station Equipment	6,378
593.00	Overhead Services	24,330
594.00	Underground Lines	6,523
595.00	Line Transformers	5,343
596.00	Street Lighting & Signal Sys.	2,117
597.00	Meters	1,786
598.00	Misc. Distribution Plant	16,971
	Total Maintenance	$76,523
	TOTAL DISTRIBUTION (1985$)	$153,854
	Escalation Amounts, 1985 to 1988	
	Labor	9,735
	Non-Labor	6,723
	Other	0
	Total	$16,458
	TOTAL DISTRIBUTION (1988$)	$170,312

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
CUSTOMER ACCOUNTS EXPENSE
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Account No.	Description	Adopted
901.0	Supervision	$6,400
902.0	Meter Reading Expenses	21,987
903.0	Customer Records and Collectibles	60,993
904.0	Uncollectible Accounts	5,660
905.0	Misc. Customer Accounts Exp.	6,216
	TOTAL CUSTOMER ACCTS. (1985$)	$101,256
	Total (Less Uncollectibles)	$95,596
	Escalation Amounts, 1985 to 1988	
	Labor	7,328
	Non-Labor	2,026
	Other	0
	Total	$9,354
	TOTAL CUSTOMER ACCTS. (1988$)	$110,609
	Total (Less Uncollectibles)	$104,950

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
CUSTOMER SERVICE AND INFORMATIONAL EXPENSES
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Account No.	Description	Adopted
	Residential & Non-Residential Conservation, Service Planning and Load Management Expenses	
907.0	Supervision	$482
908.0	Customer Assistance Expense	50,801
909.0	Informational & Instruct. Exp.	2,910
910.0	Miscellaneous	0
	TOTAL CUSTOMER SERVICES AND INFORMATIONAL (1985$)	$54,193
	Escalation Amounts, 1985 to 1988	
	Labor	1,837
	Non-Labor	2,105
	Other	0
	Total	$3,942
	TOTAL CUSTOMER SERVICES AND INFORMATIONAL (1988$)	$58,135

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
ADMINISTRATIVE & GENERAL EXPENSES
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Account No.	Description	Adopted
	Operation	
920.0	Administrative & Gen. Salaries	$109,273
921.0	Office Supplies and Expenses	24,208
922.0	Admin. & Gen. Transfer Credit	(26,162)
923.0	Outside Services Employed	7,112
924.0	Property Insurance	21,361
925.0	Injuries and Damages	23,965
926.0	Employee Pensions and Benefits	114,401
927.0	Franchise Requirements	19,827
928.0	Regulatory Commission Expenses	3,495
930.0	Other Misc. General Expenses	33,148
931.0	Rents	2,303
	Total Operation	$332,930
	Maintenance	
935.0	Maintenance of General Plant	11,683
	Total Maintenance	11,683
	TOTAL ADMIN. & GEN. (1985$)	$344,613
	Total (Less Franchise Req.)	$324,786
	Escalation Amounts, 1985 to 1988	
	Labor	11,591
	Non-Labor	5,985
	Other	0
	Total	$17,577
	TOTAL ADMIN. & GEN. (1988$)	$362,190
	Total (Less Franchise Req.)	$342,363

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
EXPENSE SUMMARY
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Description		Adopted
TOTAL NON-ESCALATED		
Steam Production	$209,254	
Nuclear Production	167,459	
Hydraulic Production	20,472	
Other Production	17,225	
Total Production		$414,410
Transmission		75,343
Distribution		153,854
Customer Accounts		101,256
Customer Service & Informational		54,193
Administrative and General		344,613
Additional Productivity		(31,027)
Total Non-Escalated (1985$)		$1,112,641
TOTAL ESCALATED		
Steam Production	229,500	
Nuclear Production	184,458	
Hydraulic Production	22,592	
Other Production	18,990	
Total Production		$455,540
Transmission		81,719
Distribution		170,312
Customer Accounts		110,609
Customer Service & Informational		58,135
Administrative and General		362,190
Additional Productivity		(33,600)
Total Escalated (1988$)		$1,204,905
TOTAL ESCALATION (1985$ to 1988$)		
Steam Production	20,247	
Nuclear Production	16,999	
Hydraulic Production	2,120	
Other Production	1,765	
Total Production		$41,131
Transmission		6,376
Distribution		16,458
Customer Accounts		9,354
Customer Service & Informational		3,942
Administrative and General		17,577
Additional Productivity		(2,573)
Total Escalation		$92,264

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
LABOR SUMMARY
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Description		Adopted
LABOR NON-ESCALATED (1985$)		
Steam Production	$62,797	
Nuclear Production	71,799	
Hydraulic Production	9,515	
Other Production	7,082	
Total Production		$151,193
Transmission		35,590
Distribution		86,309
Customer Accounts		64,972
Customer Service & Informational		16,286
Administrative and General		102,771
Additional Productivity		(12,401)
Total Non-Escalated Labor		$444,719
Labor Escalation Factor		1.11279
LABOR ESCALATED (1988$)		
Steam Production	69,880	
Nuclear Production	79,897	
Hydraulic Production	10,588	
Other Production	7,881	
Total Production		$168,246
Transmission		39,604
Distribution		96,044
Customer Accounts		72,300
Customer Service & Informational		18,123
Administrative and General		114,362
Additional Productivity		(13,800)
Total Escalated Labor		$494,879
LABOR ESCALATION (1985$ to 1988$)		
Steam Production	7,083	
Nuclear Production	8,098	
Hydraulic Production	1,073	
Other Production	799	
Total Production		$17,053
Transmission		4,014
Distribution		9,735
Customer Accounts		7,328
Customer Service & Informational		1,837
Administrative and General		11,591
Additional Productivity		(1,399)
Total Labor Escalation		$50,159

SOUTHERN CALIFORNIA EDISON COMPANY
NON-LABOR SUMMARY
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Description		Adopted
NON-LABOR NON-ESCALATED (1985$)		
Steam Production	$137,791	
Nuclear Production	93,174	
Hydraulic Production	10,957	
Other Production	10,111	
Total Production		$252,034
Transmission		24,720
Distribution		70,374
Customer Accounts		21,204
Customer Service & Informational		22,034
Administrative and General		62,649
Additional Productivity		(12,290)
Total Non-Escalated Non-Labor		$440,725
Non-Labor Escalation Factor		1.09553
NON-LABOR ESCALATED (1988$)		
Steam Production	150,955	
Nuclear Production	102,076	
Hydraulic Production	12,004	
Other Production	11,077	
Total Production		$276,112
Transmission		27,082
Distribution		77,097
Customer Accounts		23,230
Customer Service & Informational		24,139
Administrative and General		68,634
Additional Productivity		(13,464)
Total Escalated Non-Labor		$482,830
NON-LABOR ESCALATION (1985$ to 1988$)		
Steam Production	13,164	
Nuclear Production	8,901	
Hydraulic Production	1,047	
Other Production	966	
Total Production		$24,078
Transmission		2,362
Distribution		6,723
Customer Accounts		2,026
Customer Service & Informational		2,105
Administrative and General		5,985
Additional Productivity		(1,174)
Total Non-Labor Escalation		$42,104

SOUTHERN CALIFORNIA EDISON COMPANY
OTHER SUMMARY
(Thousands Of 1985 Dollars Unless Otherwise Indicated
Test Year 1988

Description		Adopted
OTHER NON-ESCALATED (1985$)		
Steam Production	$8,665	
Nuclear Production	2,486	
Hydraulic Production	0	
Other Production	32	
Total Production		$11,183
Transmission		15,033
Distribution		(2,829)
Customer Accounts		15,080
Customer Service & Informational		15,873
Administrative and General		179,193
Additional Productivity		(6,336)
Total Non-Escalated Other		$227,197
Other Escalation Factor		1.0000
OTHER ESCALATED (1988$)		
Steam Production	8,665	
Nuclear Production	2,486	
Hydraulic Production	0	
Other Production	32	
Total Production		$11,183
Transmission		15,033
Distribution		(2,829)
Customer Accounts		15,080
Customer Service & Informational		15,873
Administrative and General		179,193
Additional Productivity		(6,336)
Total Escalated Other		$227,197
OTHER ESCALATION (1985$ to 1988$)		
Steam Production	0	
Nuclear Production	0	
Hydraulic Production	0	
Other Production	0	
Total Production		$0
Transmission		0
Distribution		0
Customer Accounts		0
Customer Service & Informational		0
Administrative and General		0
Additional Productivity		0
Total Other Escalation		$0

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
TAXES OTHER THAN ON INCOME
Thousands Of 1988 Dollars
Test Year 1988

Description	Adopted
Ad Valorem Taxes	
Ca., Ariz., N.M., Nev.	$82,298
Total Ad Valorem Taxes	82,298
Payroll Taxes	
Federal Insurance Contrib. Act	36,654
Federal Unemployment Insurance	584
State Unemployment Insurance	899
Total Payroll Taxes	38,137
Miscellaneous Taxes	
Superfund tax	1,000
Miscellaneous Taxes	(458)
Total Miscellaneous Taxes	542
Total Taxes OTOI (1987$)	$120,977

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
INCOME TAX ADJUSTMENTS
Thousands Of 1988 Dollars
Test Year 1988

Description	Adopted
California Income Tax Adjustments	
Tax Depreciation (liberalized)	$456,322
Nuclear Fuel Amort. (liberalized)	(106,581)
Fuel Oil Transp. Fac. (liberalized)	(4,584)
Interest Charges	274,797
Nucl. Fuel Lease Int. Cap.	13,318
A & G expenses - capitalized	52,202
Payroll Taxes Capitalized	14,831
Ad Valorem Taxes Capitalized	9,332
Use Tax Capitalized	5,558
Ad Valorem Lien Date Adjust.	1,853
Removal Costs	28,000
Right of Way Easement Amort.	1,218
Repair Allowance	13,000
Salvage Warehouse Exp.	300
Pension Reserves	0
Amortization of PV review costs	515
Interest Synchronization	(11,187)
	$748,894
Federal Income Tax Adjustments	
Tax Depreciation (liberalized)	342,848
Nuclear Fuel Amort. (liberalized)	(106,581)
Fuel Oil Transp. Fac. (liberalized)	(4,584)
Interest Charges	274,797
Nucl. Fuel Lease Int. Cap.	13,318
A & G expenses - capitalized	11,928
Payroll Taxes Capitalized	2,966
Ad Valorem Taxes Capitalized	1,866
Use Tax Capitalized	1,112
Ad Valorem Lien Date Adjust.	1,853
Removal Costs	19,000
Right of Way Easement Amort.	1,218
Repair Allowance	11,000
Salvage Warehouse Exp.	300
Pension Reserves	0
Amortization of PV review costs	515
Leased Property ITC	(221)
Total State Taxes on Income	0
Preferred Dividend Credit	832
Contrib. in Aid of Construct.	0
	$572,167

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
TAXES ON INCOME - ADOPTED RATES
Thousands Of 1988 Dollars
Test Year 1988

Description	Adopted
California Corporation Franchise Tax	
Operating Revenues	$2,767,390
Operating Expenses	1,204,905
Nuclear Decommissioning Exp.	0
Taxes Other Than On Income	120,977
Income Tax Adjustments	748,894
California Taxable Income	$692,614
CCFT Tax Rate	0.08994
TOTAL CCFT	$62,294
Federal Income Tax	
Operating Revenues	$2,767,390
Operating Expenses	1,204,905
Nuclear Decommissioning Exp.	0
Taxes Other Than On Income	120,977
CCFT	62,294
Income Tax Adjustments	572,167
Federal Taxable Income	$807,047
FIT Tax Rate	0.34
Federal Income Tax	$274,396
Inv.Credit-Rateable Flow-thru.	(14,670)
Accl. Amortization	(1,384)
ACRS	0
Superfund Tax	0
Total Federal Income Tax	$258,342

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
DEPRECIATION EXPENSE
Thousands Of 1988 Dollars
Test Year 1988

Description	Adopted
Steam Production	$80,759
Nuclear Production	$27,640
Hydraulic Production	$4,490
Other Production	$12,245
Transmission	$60,989
Distribution	$153,933
General	$39,349
Experimental Plant	8,358
Subtotal	$387,763
Amort. of PV review costs	515
Nuclear decommissioning	0
Total Depreciation Expense	$388,278

Depreciation expense embedded in other accounts

Other Depreciation (General)	1,411
Fuel Oil Transportation Facility	4,584
Total Depreciation Expense	5,995

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
DEPRECIATION RESERVE
Thousands Of 1988 Dollars
Test Year 1988

Description	Adopted
Depreciation Reserve - BOY	
Steam Production	$949,636
Nuclear Production	150,947
Hydraulic Production	113,168
Other Production	186,219
Transmission	547,836
Distribution	1,319,333
General	112,906
Experimental Plant	26,540
Retirement work-in-progress	(11,048)
Nuclear decommissioning	0
Other depr. (General)	5,936
Fuel Oil Transp. Fac.	44,476
Depreciation Reserve - BOY	$3,445,949
Other Adjustments (excl. Depr. expense)	
Steam Production	3,829
Nuclear Production	276
Hydraulic Production	374
Other Production	40
Transmission	6,083
Distribution	49,220
General	9,233
Experimental Plant	122
Retirement work-in-progress	0
Nuclear decommissioning	0
Other depr. (General)	1,112
Fuel Oil Transp. Fac.	12
Other Adjustments (excl. depr.)	70,300
Depreciation Reserve - EOY	
Steam Production	1,026,566
Nuclear Production	178,311
Hydraulic Production	117,284
Other Production	198,424
Transmission	602,742
Distribution	1,424,046
General	143,022
Experimental Plant	34,776
Retirement work-in-progress	(11,048)
Nuclear decommissioning	0
Other depr. (General)	6,235
Fuel Oil Transp. Fac.	49,048
Depreciation Reserve - EOY	3,769,407
Depreciation Reserve - Wtd. avg.	$3,607,678

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
PLANT IN SERVICE - EOY
Thousands Of 1988 Dollars
Test Year 1988

Description	Adopted
Plant in Service - BOY	
Intangible	$113
Production Plant	
Steam	1,899,064
Nuclear	637,078
Hydraulic	283,398
Other Production	386,318
Total Production	$3,205,858
Transmission Plant	1,756,685
Distribution Plant	3,886,420
General Plant	710,153
Total Plant in Service : BOY	9,559,229
Plant in Service - Net Additions	
Intangible	$0
Production Plant	
Steam	50,194
Nuclear	42,603
Hydraulic	34,893
Other Production	12,526
Total Production	$140,216
Transmission Plant	148,673
Distribution Plant	322,811
General Plant	85,340
Total Net Additions	697,040
Plant in Service - EOY	
Intangible	$113
Production Plant	
Steam	1,949,258
Nuclear	679,681
Hydraulic	318,291
Other Production	398,844
Total Production	$3,346,074
Transmission Plant	1,905,358
Distribution Plant	4,209,231
General Plant	795,493
Total Plant in Service : EOY	10,256,269

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
PLANT IN SERVICE - WTD. AVG.
Thousands Of 1988 Dollars
Test Year 1988

Description	Adopted
Plant in Service - BOY	
Intangible	$113
Production Plant	
Steam	1,899,064
Nuclear	637,078
Hydraulic	283,398
Other Production	386,318
Total Production	$3,205,858
Transmission Plant	1,756,685
Distribution Plant	3,886,420
General Plant	710,153
Total Plant in Service : BOY	9,559,229
Plant in Service - Weighted Average Net Additions	
Intangible	$0
Production Plant	
Steam	32,849
Nuclear	54,099
Hydraulic	9,616
Other Production	10,975
Total Production	$107,539
Transmission Plant	70,367
Distribution Plant	161,888
General Plant	59,098
Total Wtd. Avg. Net Additions	398,892
Total Plant in Service - Weighted Average	
Intangible	$113
Production Plant	
Steam	1,931,913
Nuclear	691,177
Hydraulic	293,014
Other Production	397,293
Total Production	$3,313,397
Transmission Plant	1,827,052
Distribution Plant	4,048,308
General Plant	769,251
Total Plant in Service : Wtd. Avg.	9,958,121

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
OTHER FIXED CAPITAL
Thousands Of 1988 Dollars
Test Year 1988

Description	Adopted
Nuclear Fuel	
Nuclear Fuel - BOY	$0
Nuclear Fuel - Net Additions	0
Nuclear Fuel - EOY	0
Nuclear Fuel - Wtd. Avg. Net Additions	0
Nuclear Fuel - Wtd. Avg.	0
Unclassified Electric Plant	
Unclass. Elect. Plant - BOY	293,057
Unclass. Elect. Plant - Net Additions	(14,577)
Unclass. Elect. Plant - EOY	278,480
Unclass. Elect. Plant - Wtd. Avg. Net Ad	(57,910)
Unclass. Elect. Plant - Wtd. Avg.	235,147
Plant Held for Future Use	
PHFU - BOY	116,428
PHFU - Net Additions	7,221
PHFU - EOY	123,649
PHFU - Wtd. Avg. Net Additions	3,606
PHFU - Wtd. Avg.	120,034

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
WEIGHTED AVERAGE DEPRECIATED RATE BASE
Thousands Of 1988 Dollars
Test Year 1988

Description	Adopted
FIXED CAPITAL @ BEGINNING OF YEAR	
Plant in Service	9,559,229
Nuclear Fuel	0
Unclassified Elect. Plant	293,057
PHFU	116,428
Total Fixed Capital - BOY	9,968,714
WTD. AVG. NET ADDITIONS	
Plant in Service	398,892
Nuclear Fuel	0
Unclassified Elect. Plant	(57,910)
PHFU	3,606
Total Wtd. Avg. Additions	344,588
Tot. Wtd. Avg. Fixed Capital	10,313,302
ADJUSTMENTS	
Cust. Adv. for Construction	(58,907)
Total Adjustments	(58,907)
WORKING CAPITAL	
Fuel Stock - Coal / Misc.	0
Materials & Supplies	118,343
Working Cash	(12,597)
Total Working Capital	105,746
Tot. Before Ded. for Reserves	10,360,141
DEDUCTIONS FOR RESERVES	
Wtd. Avg.Depreciation Reserve	3,607,678
Taxes Def. - Acc. Amort.	3,436
Taxes Def. - ACRS	325,594
Taxes Def. - Ref. Ret. Debt	69,689
Unfunded Pension Reserve	36,575
Total Ded. for Reserves	4,042,972
Weighted Average Depreciated Rate Base	6,317,168

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
DETERMINATION OF AVERAGE AMOUNTS OF WORKING
CASH CAPITAL SUPPLIED BY INVESTORS
Thousands Of 1988 Dollars
Test Year 1988

Description	Adopted
Operational Cash Requirements	
Cash	$2,633
Special Deposits	481
Working Funds	2,892
Total	$6,006
Less: Amounts Not Supplied By Investors	
Accrued Vacation & Empl. Witholdings	37,447
Credit recd. for capitlized supplies	39,322
Total	$76,769
Subtotal, Total Company	($70,763)
Electric Department Allocation Percentag	100%
Electric Department Allocation	(70,763)
Prepayments - Electric Department	0
Misc. Deferred Credits - Electric	0
Total Operational Cash Requirement	($70,763)
Plus: Average Amount Required	
Avg. Amt. Req. as a Result of Paying Expenses in Advance of Collecting Revenues	58,166
Total	$58,166
Average Net Amount of Working Cash Capital Supplied by Investors	($12,597)

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
DEVELOPMENT OF AVERAGE LAG IN PAYMENT OF EXPENSES
Thousands Of 1988 Dollars
Test Year 1988

Description	Expense	Average Lag Days	Product
	(A)	(B)	(C=AxB)
Fed. Income Tax	$231,433	121.19	28047370
FIT: SIT Ded. Ti	0	121.19	0
FIT: SIT Ded. Ti	0	486.19	0
State Income Tax	54308	83.59	4539645
Fed. Misc. Tax	0	0.00	0
Franchise Requir	35639	269.15	9592324
Fuel Oil	67819	16.36	1109519
Coal	125669	31.24	3925900
Natural Gas Purc	531021	37.36	19838945
Nuclear Fuel	162863	75.25	12255441
Purchased Power	1304150	38.15	49753323
Company Labor	494879	12.00	5938543
Property Insuran	20413	0.00	0
Injuries and Dam	22545	0.00	0
Pension Expense	106567	0.00	0
Ad Val.Tax - Ari	1930	210.43	406130
Ad Val.Tax - Nev	961	-61.36	-58967
Ad Val.Tax - New	1818	51.55	93718
Goods and Servic	495154	29.27	14493145
Materials From S	39861	0.00	0
Depreciation	388278	0.00	0
Ad Val.Tax - CA	77589	37.44	2904932
FICA Tax	36654	6.62	242649
Unemp. Tax - Fed	584	75.22	43948
Unemp. Tax - Cal	899	73.49	66062
Misc. taxes	-458	0.00	0
SIT - Az.,NM,Uta	164	126.78	20732
Hazardous Waste	320	363.50	116320
Deferred Income	67301	0.00	0
Adj. to ERTA Tax	-67301	121.19	-8156208
TOTAL	4201060		145173468

Exp. Lag Days	34.56	= (C)/(A)
Revenue Lag Days	39.61	
Adj. to Rate Bas	58,166	
Rate Base Factor	6,259,003	
New Rate Base	$6,317,168	

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
SUMMARY OF EARNINGS AT ADOPTED PRESENT RATE
REVENUES AND EXPENSES
(Thousands Of 1988 Dollars Unless Otherwise Indicated
Test Year 1988

Description	Adopted
Operating Revenues	
Revenues	$2,767,390
Total Operating Revenues	$2,767,390
Operating Expenses	
Production	414,410
Transmission	75,343
Distribution	153,854
Customer Accounts	95,596
Uncollectibles	5,660
Customer Service & Informational	54,193
Administrative & General	324,786
Franchise Requirements	19,827
Additional Productivity	(31,027)
Subtotal (1985 Dollars)	$1,112,641
Labor Escalation Amount	50,159
Non-Labor Escalation Amount	42,104
Subtotal (1988 Dollars)	$1,204,905
Depreciation	388,278
Nuclear Decommissioning Exp.	0
Taxes Other Than On Income	120,977
CA Corporation Franchise Tax	62,294
Federal Income Tax	258,342
Total Operating Expenses	$2,034,796
Net Operating Income	$732,594
Rate Base	6,317,168
Rate of Return (Total System)	11.60%

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - CPUC Jurisdiction
SUMMARY OF EARNINGS AT ADOPTED PRESENT RATE
REVENUES AND EXPENSES
(Thousands Of 1988 Dollars Unless Otherwise Indicated
Test Year 1988

Description	Jurisdictional Factors	Adopted
Operating Revenues		
Revenues	0.9764	$2,702,183
Total Operating Revenues		2,702,183
Operating Expenses		
Production	0.9805	406,329
Transmission	0.9818	73,968
Distribution	0.9985	153,623
Customer Accounts	0.9998	95,577
Uncollectibles	1.0000	5,660
Cust. Serv. & Inform.	1.0000	54,193
Administrative & Gen.	0.9891	321,246
Franchise Requirements	0.9983	19,793
Additional Productivity	0.9884	(30,667)
Subtotal (1985 Dollars)		$1,099,721
Labor Escalation Amount	0.9884	49,577
Non-Labor Escl. Amount	0.9884	41,616
Subtotal (1988 Dollars)		$1,190,915
Depreciation	0.9858	382,765
Nuclear Decommissioning	1.0000	0
Taxes Other Than On Inc	0.9872	119,429
CA Corporation Franchis	0.9880	58,635
Federal Income Tax	0.9880	245,226
Total Operating Expenses		$1,996,968
Net Operating Income		$705,214
Rate Base	0.9873	6,236,940
Rate of Return		11.31%

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - CPUC Jurisdiction
ADOPTED SUMMARY OF EARNINGS
(Thousands Of 1988 Dollars Unless Otherwise Indicated
Test Year 1988

Description	
Operating Revenues	
Adopted Present Rate Revenues	$2,702,183
Authorized incr. in Revenues (*)	(56,298)
Subtotal	2,645,884
Authorized TOU meter charges (*)	370
Total Operating Revenues	$2,646,254
Operating Expenses	
Production	446,657
Transmission	80,227
Distribution	170,056
Customer Accounts	104,929
Uncollectibles	5,539
Cust. Serv. & Inform.	58,135
Administrative & Gen.	338,631
Franchise Requirements	19,383
Additional Productivity	(33,210)
Subtotal (1988 Dollars)	$1,190,348
Depreciation	382,765
Nuclear Decommissioning Exp.	0
Taxes Other Than On Income	119,429
CA Corporation Franchise Tax	53,622
Federal Income Tax	227,982
Total Operating Expenses	$1,974,144
Net Operating Income	$671,740
Rate Base	6,236,940
Rate of Return	10.77%

(*) AUTH. CHANGE IN OPERATING REVENUES : ($55,929)

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
DEVELOPMENT OF THE NET-TO-GROSS MULTIPLIER
Test Year 1988

Description	(A)	(B)	(C=A*B)
Gross Operating Revenues			1.000000
Less: Uncoll.	0.002140	1.000000	0.002140
			0.997860
Less: Franchise	0.007300	1.000000	0.007300
			0.990560
Less: S.I.T.	0.089940	0.990560	0.089091
			0.901469
Less: F.I.T.	0.340000	0.901469	0.306499
Net Operating Revenues			0.594970
Uncoll. & F.F. Factor			1.009514
State & Fed. Tax Factor			1.664892
N-T-G Multiplier			1.680758

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department
ESCALATION FACTORS - Total Company
COST OF CAPITAL - CPUC Jurisdiction
Test Year 1988

Description		Adopted
LABOR ------------>	1986	3.880%
ESCALATION FACTORS	1987	3.500%
	1988	3.500%
	1989	4.840%
	1990	4.720%
NON-LABOR -------->	1986	1.880%
ESCALATION FACTORS	1987	2.990%
	1988	4.410%
	1989	4.640%
	1990	4.860%
OTHER ------------>	ALL YEARS	0.000%

COMPOSITE ESCALATION FACTORS

LABOR	1985 TO 1988	11.279%
NON-LABOR	1985 TO 1988	9.553%
OTHER	1985 TO 1988	0.000%

	COST	CAPITALIZATION	WTD. COST
Debt	9.26%	47.00%	4.35%
Pref. Stock	7.88%	7.00%	0.55%
Common equity	12.75%	46.00%	5.87%
Auth. Return on Rate Base (CPUC Jurisdiction) :			10.77%

ATTRITION YEAR 1989

	Expenses for AY1989 in 000's of 1988$	Expenses for AY1989 in 000's of 1988$ (Calif.)	Transfer of Other Expenses to Labor/ Non-Labor	Expenses for AY1989 in 000's of 1988$ for Attrition purposes
	ADOPTED	IN	GRC	
Production (Juris. Alloc. Factor =			0.9805	
Labor	168,246	164,965	0	164,965
Non Labor	276,112	270,728	10,965	281,693
Other	11,183	10,965	(10,965)	0
	455,540	446,657	0	446,657
Transmission (Juris. Alloc. Factor =			0.9818	
Labor	39,604	38,881	0	38,881
Non Labor	27,082	26,587	14,759	41,346
Other	15,033	14,759	(14,759)	0
	81,719	80,227	0	80,227
Distribution (Juris. Alloc. Factor =			0.9985	
Labor	96,044	95,900	0	95,900
Non Labor	77,097	76,982	(2,825)	74,157
Other	(2,829)	(2,825)	2,825	0
	170,312	170,056	0	170,056
Customer Accounts (Juris. Alloc. Factor			0.9998	
Labor	72,300	72,286	0	72,286
Non Labor	23,230	23,225	9,418	32,643
Other	15,080	15,077	(9,418)	5,658
	110,609	110,587	0	110,587
Cust.Serv.&Info. (Juris. Alloc. Factor			1.0000)	
Labor	18,123	18,123	0	18,123
Non Labor	24,139	24,139	0	24,139
Other	15,873	15,873	0	15,873
	58,135	58,135	0	58,135
Admin. & Gen. (Juris. Alloc. Factor =			0.9891	
Labor	114,362	113,116	54,191	167,307
Non Labor	68,634	67,886	99,151	167,037
Other	179,193	177,240	(153,342)	23,898
	362,190	358,242	0	358,242

	Expenses for AY1989 in 000's of 1988$	Expenses for AY1989 in 000's of 1988$ (Calif.)	Transfer of Other Expenses to Labor/ Non-Labor	Expenses for AY1989 in 000's of 1988$ for Attrition purposes
	ADOPTED	IN	GRC	
Productivity Adj. (Juris. Alloc. Factor			0.9884	
Labor	(13,800)	(13,640)	0	(13,640)
Non Labor	(13,464)	(13,308)	(6,262)	(19,570)
Other	(6,336)	(6,262)	6,262	0
	(33,600)	(33,210)	0	(33,210)
Nucl. Refuel. Exp. (Juris. Alloc. Facto			0.9805	
Labor	(2,130)	(2,088)	0	(2,088)
Non Labor	(25,046)	(24,558)	0	(24,558)
Other	0	0	0	0
	(27,176)	(26,646)	0	(26,646)
TOTAL O&M EXPENSES				
Labor	492,749	487,542	54,191	541,732
Non Labor	457,783	451,681	125,206	576,887
Other	227,197	224,826	(179,396)	45,429
	1,177,729	1,164,049	0	1,164,049

Labor Base for AY 1989 in 1988$ (Adopted in GRC)	$541,732	
1988 Labor Escalation (estimated in GRC)	3.50%	
1987 Labor Escalation (estimated in GRC)	3.50%	
1986 Labor Escalation (estimated in GRC)	3.88%	
1986 Labor Escalation (use recorded)	3.88%	
1987 Labor Escalation (use recorded)	3.50%	
1988 Labor Escalation (use updated estimate)	3.50%	
1989 Labor Escalation (use updated estimate of CPI-Wage Earners)	4.84%	
Labor Base for AY 1989 in 1989$	567,952	
Labor Escalation for AY 1989 in 1989$	26,220	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.009514	
Increase in Revenue Requirement	26,469	(1)

Non-Labor Base for AY 1989 in 1988$ (Adopted in GRC	576,887	
1988 Non-Labor Escalation (estimated in GRC)	4.41%	
1987 Non-Labor Escalation (estimated in GRC)	2.99%	
1986 Non-Labor Escalation (estimated in GRC)	1.88%	
1986 Non-Labor Escalation (recorded)	1.88%	
1987 Non-Labor Escalation (recorded)	2.99%	
1988 Non-Labor Escalation (use updated estimate)	4.41%	
1989 Non-Labor Escalation (use updated estimate)	4.64%	
Non-Labor Base for AY 1989 in 1989$	603,654	
Non-Labor Escalation for AY 1989 in 1989$	26,768	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.009514	
Increase in Revenue Requirement	27,022	(2)

Nuclear Refueling Expense (Juris. Alloc 0.9805)

Increase in Labor expense	(2,130)	
Increase in Non-Labor expense	(25,046)	
Increase in Other expense	0	
Increase in Nuclear Refueling Expense	(27,176)	
Increase in Nuclear Refueling Expense (Calif)	(26,646)	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.009514	
Increase in Revenue Requirement	(26,900)	(3)

Depreciation Exp. (Juris. Alloc. Factor 0.9858)

System avg. Depreciation Rate (Adopted in GRC)	3.9593%	
Increase in Wtd. Avg. Plant in Service for AY1989 (Adopted in GRC)	555,614	
Increase in Depreciation expense	21,998	
Increase in Depreciation expense (Calif.)	21,686	
Net-to-Gross Multiplier (Adopted in GRC)	1.680758	
Increase in Revenue Requirement	36,449	(4)

Ad Valorem Taxes (Juris. Alloc. Factor 0.9872)

System avg. Ad Valorem Tax Rate (Adopted in GRC)	0.8024%	
Increase in AY1989 EOY Plant in Service from TY1988 EOY Plant in Service (Adopted in GRC)	449,906	
Increase in Ad Valorem Taxes	3,610	
Increase in Ad Valorem Taxes (Calif.)	3,564	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.009514	
Increase in Revenue Requirement	3,598	(5)

Accel. Amort. (Juris. Alloc. Factor = 0.9880)

Attrition Year 1989 (Adopted in GRC)	(1,384)	
Test Year 1988 (Adopted in GRC)	(1,384)	
Increase in Accel. Amortization	0	
Increase in Accel. Amortization (Calif.)	0	
Net-to-Gross Multiplier (Adopted in GRC)	1.680758	
Increase in Revenue Requirement	0	(6)

State Tax Depr. (Juris. Alloc. Factor = 0.9880)

State Tax Depr. Rate (Adopted in GRC)		4.4492%	
Increase in AY1989 EOY Plant in Service from TY1988 EOY Plant in Service (Adopted in GRC)		449,906	
Increase in State Tax Depreciation		20,017	
Increase in State Tax Depreciation (Calif.)		19,777	
Increase in CCFT (Tax Rate =	8.9940%	(1,779)	
Increase in FIT (Tax Rate =	34.0000%	605	
Increase in State & Federal Taxes		(1,174)	
Net-to-Gross Multiplier (Adopted in GRC)		1.680758	
Increase in Revenue Requirement		(1,973)	(7)

Federal Tax Depr. (Juris. Alloc. Factor 0.9880)			
Federal Tax Depr. Rate (Adopted in GRC)		3.3428%	
Increase in AY1989 EOY Plant in Service from TY1988 EOY Plant in Service (Adopted in GRC)		449,906	
Increase in Federal Tax Depreciation		15,040	
Increase in Federal Tax Depreciation (Calif.)		14,859	
Increase in Federal Taxes (Tax Rate	34.0000%	(5,052)	
Net-to-Gross Multiplier (Adopted in GRC)		1.680758	
Increase in Revenue Requirement		(8,491)	(8)

ITC Normalized (Juris. Alloc. Factor = 0.9880) (Applicable to IRC Sec. 46(f)(2) utilities only.)		
Attrition Year 1989 (Adopted in GRC)	(13,327)	
Test Year 1988 (Adopted in GRC)	(14,670)	
Increase in ITC normalized	1,343	
Increase in ITC normalized (Calif.)	1,327	
Net-to-Gross Multiplier (Adopted in GRC)	1.680758	
Increase in Revenue Requirement	2,230	(9)

Interest Synchro. (Juris. Alloc. Factor 0.9880) (Applicable to IRC Sec. 46(f)(2) utilities only.)			
ITC Normalized in TY1988 (from above)		14,670	
Wtd. cost of Long Term Debt (Adopted in AY1989)		4.35%	
Increase in CCFT interest		638	
Increase in CCFT (Tax Rate =	8.9940%	(57)	
Increase in FIT (Tax Rate =	34.0000%	20	
Increase in State & Federal Taxes		(38)	
Increase in State & Federal Taxes (Calif.)		(37)	
Net-to-Gross Multiplier (Adopted in GRC)		1.680758	
Increase in Revenue Requirement		(63)	(10)

Rate Base (Juris. Alloc. Factor = 0.9873)

Wtd. avg. Depr Rate Base for TY1988 (Adopted in GRC	6,317,168
Plant in Service (Adopted in GRC)	
Wtd. avg. Additions for TY1988	(398,892)
Net Additions for TY1988	697,040
Wtd. avg. Additions for AY1989	257,466
Unclassified Electric Plant (Adopted in GRC)	
Wtd. avg. Additions for TY1988	57,910
Net Additions for TY1988	(14,577)
Wtd. avg. Additions for AY1989	(3,525)
PHFFU (Adopted in GRC)	
Wtd. avg. Additions for TY1988	(3,606)
Net Additions for TY1988	7,221
Wtd. avg. Additions for AY1989	(4,310)
Depreciation Reserve (Adopted in GRC)	
Wtd. avg. Depreciation Reserve for TY1988	3,607,678
Wtd. avg. Depreciation Reserve for AY1989	(3,954,856)
Taxes Deferred - ACRS (Adopted in GRC)	
Wtd. avg. Deferred Taxes - ACRS for TY1988	325,594
Wtd. avg. Deferred Taxes - ACRS for AY1989	(394,371)
Wtd. avg. Depr Rate Base for AY1989	6,495,941
Wtd. avg. Depr. Rate Base in TY1988 (Adopted in GRC	6,317,168
Wtd. avg. Depr. Rate Base in AY1989 (Adopted in GRC	6,495,941
Wtd. avg. Depr. Rate Base in TY 1988 (Calif.)	6,236,940
Wtd. avg. Depr. Rate Base in AY 1989 (Calif.)	6,413,442
Long-term Debt	
Return on Debt in TY 1988 (Adopted in GRC)	9.26%
Debt capitalization in TY 1988 (Adopted in GRC)	47.00%
Wtd. cost of Debt for Test Year 1988	4.35%
Return on Debt in AY 1989 (Adopted in AY1989)	9.26%
Debt capitalization in AY 1989 (Adopted in AY1989)	47.00%
Wtd. cost of Debt for Attrition Year 1989	4.35%

Increase in Debt cost in Attrition Year 1989	7,678	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.009514	
Increase in Revenue Requirement	7,751	(11)

Preferred Stock

Return on Pref. Stock in TY 1988 (Adopted in GRC)	7.88%	
Pref.Stk. capitalization in TY1988 (Adopted in GRC)	7.00%	
Wtd. cost of Preferred Stock for Test Year 1988	0.55%	
Return on Pref. Stock in AY1989 (Adopted in AY1989)	7.88%	
Pref.Stk. capitalization AY1989 (Adopted in AY1989)	7.00%	
Wtd. cost of Preferred Stock for Att. Year 1989	0.55%	
Increase in Pref. Stock cost in Att. Year 1989	971	
Net-to-Gross Multiplier (Adopted in GRC)	1.680758	
Increase in Revenue Requirement	1,632	(12)

Common Equity

Return on Common Equity in TY 1988 (Adopted in GRC)	12.75%	
Com. Equity capitalization TY 1988 (Adopted in GRC)	46.00%	
Wtd. cost of Common Equity for Test Year 1988	5.87%	
Return on Common Equity AY 1989 (Adopted in AY1989)	12.75%	
Com. Eq. capitalization AY 1989 (Adopted in AY1989)	46.00%	
Wtd. cost of Common Equity for Att. Year 1989	5.87%	
Increase in Common Equity cost in Att. Year 1989	10,361	
Net-to-Gross Multiplier (Adopted in GRC)	1.680758	
Increase in Revenue Requirement	17,414	(13)

RATEBASE MONITORING

Wtd. avg. Depr.RateBase in TY1988 (Adopted in GRC)	6,317,168
Wtd. avg. Depr.RateBase in TY1988 (use updated est.	6,100,000
Wtd. avg. Depr.RateBase in AY1989 (Adopted in GRC)	6,495,941
Wtd. avg. Depr.RateBase in AY1989 (use updated est.	6,400,000

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
REVENUE REQUIREMENTS FOR ATTRITION YEAR 1989
Thousands Of 1989$

ITEM	ATTRITION YEAR 1989	
O & M EXPENSES :		
Labor Escalation	$26,469	(1)
Non-Labor Escalation	27,022	(2)
Nuclear Refueling expense	(26,900)	(3)
Total O&M Expenses	26,592	
CAPITAL RELATED ITEMS :		
Book Depreciation Expenses	36,449	(4)
Ad Valorem Taxes	3,598	(5)
Accelerated Amortization	0	(6)
State Tax Depreciation	(1,973)	(7)
Federal Tax Depreciation	(8,491)	(8)
ITC normalized	2,230	(9)
Interest Synchronization	(63)	(10)
Debt cost	7,751	(11)
Preferred Stock cost	1,632	(12)
Common Equity cost	17,414	(13)
Total Capital Related Items	58,546	
OTHER AUTHORIZED ITEMS :		
Jurisdictional Allocation change	9,800 s	
QF Program Adjustment	(200) s	
Hydro Automation Adjustment	(356) s	
Two-Shifting Adjustment	0	
Nuclear Regulatory Commission Fee	0	
Optional/TOU meter charges	1,013	
Total Other Authorized Items	10,257	
ADD'L REVENUE REQUIREMENTS ---->	$95,394	
Exclude % attributable to Large Light & Power (Adopted in OIR 86-10-001)	45.00%	
TOTAL ADD'L REVENUE REQUIREMENTS ---->	52,467	

ATTRITION YEAR 1990

	Expenses for AY1990 in 000's of 1988$	Expenses for AY1990 in 000's of 1988$ (Calif.)	Transfer of Other Expenses to Labor/ Non-Labor	Expenses for AY1990 in 000's of 1988$ for Attrition purposes
	ADOPTED IN GRC			
Nuclear Refueling (Juris. Alloc. Factor 0.9805)				
Labor	1,059	1,039	0	1,039
Non Labor	28,505	27,949	0	27,949
Other	0	0	0	0
	29,564	28,988	0	28,988

Labor Base for nucl. refuel. for AY1990 in 1988$	$1,039
1988 Labor Escalation (estimated in GRC)	3.50%
1987 Labor Escalation (estimated in GRC)	3.50%
1986 Labor Escalation (estimated in GRC)	3.88%
1986 Labor Escalation (use recorded)	3.88%
1987 Labor Escalation (use recorded)	3.50%
1988 Labor Escalation (use recorded)	3.50%
1989 Labor Escalation (use updated estimate of CPI-Wage Earners)	4.84%
1990 Labor Escalation (use updated estimate of CPI-Wage Earners)	4.72%
Labor Base for nucl. refueling AY 1990 in 1990$	1,140
Non-Labor Base for nucl. refuel. for AY1990 in1988$	27,949
1988 Non-Labor Escalation (estimated in GRC)	4.41%
1987 Non-Labor Escalation (estimated in GRC)	2.99%
1986 Non-Labor Escalation (estimated in GRC)	1.88%
1986 Non-Labor Escalation (use recorded)	1.88%
1987 Non-Labor Escalation (use recorded)	2.99%
1988 Non-Labor Escalation (use recorded)	4.41%
1989 Non-Labor Escalation (use updated estimate)	4.64%
1990 Non-Labor Escalation (use updated estimate)	4.86%
Non-Labor Base for nucl. refueling AY1990 in1990$	30,667
Total Labor & Non-Labor expenses for nuclear refueling for AY1990 in 1990$	31,807
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.009514
Increase in Revenue Requirement	32,110 (14)

Labor Base

Total Labor Base for AY 1990 in 1989$	567,952	
1989 Labor Escalation (estimated in GRC)	4.84%	
1988 Labor Escalation (estimated in AY1989)	3.50%	
1988 Labor Escalation (use recorded)	3.50%	
1989 Labor Escalation (use updated estimate)	4.84%	
1990 Labor Escalation (use updated estimate of CPI-Wage Earners)	4.72%	
Labor Base for AY 1990 in 1990$	594,760	
Labor Escalation for AY 1990 in 1990$	26,807	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.009514	
Increase in Revenue Requirement	27,062	(15)

Non-Labor Base

Non-Labor Base for AY 1989 (Adopted in AY1989)	$603,654	
1989 Non-Labor Escalation (estimated in GRC)	4.64%	
1988 Non-Labor Escalation (estimated in AY1989)	4.41%	
1988 Non-Labor Escalation (use recorded)	4.41%	
1989 Non-Labor Escalation (use updated estimate)	4.64%	
1990 Non-Labor Escalation (use updated estimate)	4.86%	
Non-Labor Base for AY 1990 in 1990$	632,992	
Non-Labor Escalation for AY 1990 in 1990$	29,338	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.009514	
Increase in Revenue Requirement	29,617	(16)

Depreciation Exp. (Juris. Alloc. Factor 0.9858)

System avg. Depreciation Rate (Adopted in GRC)	3.9593%	
Increase in Wtd. Avg. Plant in Service for AY1990 (Adopted in GRC)	441,711	
Increase in Depreciation expense	17,489	
Increase in Depreciation expense (Calif.)	17,240	
Net-to-Gross Multiplier (Adopted in GRC)	1.680758	
Increase in Revenue Requirement	28,977	(17)

Ad Valorem Taxes (Juris. Alloc. Factor 0.9872)			
System avg. Ad Valorem Tax Rate (Adopted in GRC)		0.8024%	
Increase in AY1990 EOY Plant in Service from AY1989 EOY Plant in Service (Adopted in GRC)		435,585	
Increase in Ad Valorem Taxes		3,495	
Increase in Ad Valorem Taxes (Calif.)		3,450	
Uncoll. & Franchise Fee Factor (Adopted in GRC)		1.009514	
Increase in Revenue Requirement		3,483	(18)

Accel. Amort. (Juris. Alloc. Factor = 0.9880)			
Attrition Year 1990 (Adopted in GRC)		(24)	
Attrition Year 1989 (adopted in GRC)		(1,384)	
Increase in Accel. Amortization		1,360	
Increase in Accel. Amortization (Calif.)		1,344	
Net-to-Gross Multiplier (Adopted in GRC)		1.680758	
Increase in Revenue Requirement		2,258	(19)

State Tax Depr. (Juris. Alloc. Factor = 0.9880)			
State Tax Depr. Rate (Adopted in GRC)		4.4492%	
Increase in AY1990 EOY Plant in Service from AY1989 EOY Plant in Service (Adopted in GRC)		435,585	
Increase in State Tax Depreciation		19,380	
Increase in State Tax Depreciation (Calif.)		19,148	
Increase in CCFT (Tax Rate =	8.9940%	(1,722)	
Increase in FIT (Tax Rate =	34.0000%	586	
Increase in State & Federal Taxes		(1,137)	
Net-to-Gross Multiplier (Adopted in GRC)		1.680758	
Increase in Revenue Requirement		(1,910)	(20)

Federal Tax Depr. (Juris. Alloc. Factor	0.9880)		
Federal Tax Depr. Rate (Adopted in GRC)		3.3428%	
Increase in AY1990 EOY Plant in Service from AY1989 EOY Plant in Service (Adopted in GRC)		435,585	
Increase in Federal Tax Depreciation		14,561	
Increase in Federal Tax Depreciation (Calif.)		14,386	
Increase in Federal Taxes (Tax Rate	34.0000%	(4,891)	
Net-to-Gross Multiplier (Adopted in GRC)		1.680758	
Increase in Revenue Requirement		(8,221)	(21)

ITC Normalized (Juris. Alloc. Factor =	0.9880)		
(Applicable to IRC Sec. 46(f)(2) utilities only.)			
Attrition Year 1990 (Adopted in GRC)		(12,065)	
Attrition Year 1989 (adopted in GRC)		(13,327)	
Increase in ITC normalized		1,262	
Increase in ITC normalized (Calif.)		1,247	
Net-to-Gross Multiplier (Adopted in GRC)		1.680758	
Increase in Revenue Requirement		2,096	(22)

INTEREST SYNCHRO. (Juris. Alloc. Factor	0.9880)		
(Applicable to IRC Sec. 46(f)(2) utilities only.)	)		
ITC Normalized in AY1990 (from above)		12,065	
Wtd. cost of Long Term Debt (Adopted in AY1990)		4.35%	
Increase in CCFT interest		525	
Increase in CCFT (Tax Rate =	8.9940%	(47)	
Increase in FIT (Tax Rate =	34.0000%	16	
Increase in State & Federal Taxes		(31)	
Increase in State & Federal Taxes (Calif.)		(31)	
Net-to-Gross Multiplier (Adopted in GRC)		1.680758	
Increase in Revenue Requirement		(52)	(23)

Rate Base (Juris. Alloc. Factor = 0.9873)

Wtd. avg. Depr Rate Base for AY1989 (Adopted in GRC	6,495,941

Plant in Service (Adopted in GRC)

Wtd. avg. Additions for AY1989	(257,466)
Net Additions for AY1989	449,906
Wtd. avg. Additions for AY1990	249,271

Unclassified Electric Plant (Adopted in GRC)

Wtd. avg. Additions for AY1989	3,525
Net Additions for AY1989	(887)
Wtd. avg. Additions for AY1990	(2,638)

PHFFU (Adopted in GRC)

Wtd. avg. Additions for TY1988	4,310
Net Additions for TY1988	(8,631)
Wtd. avg. Additions for AY1989	0

Depreciation Reserve (Adopted in GRC)

Wtd. avg. Depreciation Reserve for AY1989	3,954,856
Wtd. avg. Depreciation Reserve for AY1990	(4,335,219)

Taxes Deferred - ACRS (Adopted in GRC)

Wtd. avg. Deferred Taxes - ACRS for AY1989	394,371
Wtd. avg. Deferred Taxes - ACRS for AY1990	(466,055)
Wtd. avg. Depr Rate Base for AY1990	6,481,284

Wtd. avg. Depr. Rate Base in Attrition Year 1989	6,495,941
Wtd. avg. Depr. Rate Base in Attrition Year 1990	6,481,284
Wtd. avg. Depr. Rate Base in AY 1989 (Calif.)	6,413,442
Wtd. avg. Depr. Rate Base in AY 1990 (Calif.)	6,398,972

Long-term Debt

Return on Debt in AY 1989 (Adopted in AY1989)	9.26%
Debt capitalization in AY 1989 (Adopted in AY1989)	47.00%
Wtd. cost of Debt for Attrition Year 1989	4.35%
Return on Debt in AY 1990 (Adopted in AY1990)	9.26%
Debt capitalization in AY 1990 (Adopted in AY1990)	47.00%
Wtd. cost of Debt for Attrition Year 1990	4.35%

Increase in Debt cost in Attrition Year 1990	(629)	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.009514	
Increase in Revenue Requirement	(635)	(24)

Preferred Stock

Return on Pref. Stock in AY 1989 (Adopted in AY1989	7.88%	
Pref.Stk. capitalization AY 1989 (Adopted in AY1989	7.00%	
Wtd. cost of Preferred Stock for Test Year 1989	0.55%	
Return on Pref. Stock in AY 1990 (Adopted in AY1990	7.88%	
Pref.Stk. capitalization AY 1990 (Adopted in AY1990	7.00%	
Wtd. cost of Preferred Stock for Att. Year 1990	0.55%	
Increase in Pref. Stock cost in Att. Year 1990	(80)	
Net-to-Gross Multiplier (Adopted in GRC)	1.680758	
Increase in Revenue Requirement	(134)	(25)

Common Equity

Return on Com. Eq. in AY 1989 (Adopted in AY1989)	12.75%	
Com. Eq. capitalization AY 1989 (Adopted in AY1989)	46.00%	
Wtd. cost of Common Equity for Test Year 1989	5.87%	
Return on Com. Eq. in AY 1990 (Adopted in AY1990)	12.75%	
Com. Eq. capitalization AY 1990 (Adopted in AY1990)	46.00%	
Wtd. cost of Common Equity for Att. Year 1990	5.87%	
Increase in Common Equity cost in Att. Year 1990	(849)	
Net-to-Gross Multiplier (Adopted in GRC)	1.680758	
Increase in Revenue Requirement	(1,428)	(26)

RATEBASE MONITORING

Wtd. avg. Depr.Rate Base in TY1988 (Adopted in GRC)	6,317,168
Wtd. avg. Depr.Rate Base in TY1988 (estimated at the time of filing for AY 1989)	6,100,000
Wtd. avg. Depr.RateBase in TY1988 (recorded)	6,200,000
Wtd. avg. Depr.RateBase in AY1989 (Adopted in GRC)	6,495,941
Wtd. avg. Depr.RateBase in AY1989 (estimated at the time of filing for AY 1989)	6,400,000
Wtd. avg. Depr.RateBase in AY1989 (use updated est.	6,500,000
Wtd. avg. Depr.RateBase in AY1990 (Adopted in GRC)	6,481,284
Wtd. avg. Depr.RateBase in AY1990 (use updated est.	6,800,000

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Department - Total Company
REVENUE REQUIREMENTS FOR ATTRITION YEAR 1990
Thousands Of 1990$

ITEM	ATTRITION YEAR 1990	
O & M EXPENSES :		
Nuclear Refueling Expense	32,110	(14)
Labor Escalation	$27,062	(15)
Non-Labor Escalation	29,617	(16)
Total O&M Expenses	88,789	
CAPITAL RELATED ITEMS :		
Book Depreciation Expenses	28,977	(17)
Ad Valorem Taxes	3,483	(18)
Accelerated Amortization	2,258	(19)
State Tax Depreciation	(1,910)	(20)
Federal Tax Depreciation	(8,221)	(21)
ITC normalized	2,096	(22)
Interest Synchronization	(52)	(23)
Debt cost	(635)	(24)
Preferred Stock cost	(134)	(25)
Common Equity cost	(1,428)	(26)
Total Capital Related Items	24,434	
OTHER AUTHORIZED ITEMS :		
Jurisdictional Allocation change	0	
QF Program Adjustment	(350)	
Nuclear Regulatory Commission Fee	0	
Optional TOU meter charges	1,560	
Total Other Authorized Items	1,210	
ADD'L REVENUE REQUIREMENTS ---->	$114,433	
Exclude % attributable to Large Light & Power (Adopted in OIR 86-10-001)	45.00%	
TOTAL ADD'L REVENUE REQUIREMENTS ---->	62,938	

APPENDIX E

SOUTHERN CALIFORNIA EDISON COMPANY
TEST YEAR 1988 - CALIFORNIA JURISDICTION
REVENUE CHANGES ASSUMED FOR REVENUE ALLOCATION AND RATE DESIGN

ITEM	PRESENT RATE REVENUES **	ADOPTED REVENUES	REVENUE CHANGES
	($Million)	($Million)	($Million)
BASE:			
Base (GRC)	$ (see below)	$ (see below)	$ (see below)
DECOMM'G	0.0	100.3	100.3
* MAAC pre-COD tfr	0.0	501.6	501.6
* IMAAC PV-1,2 tfr	0.0	42.7	42.7
Palo Verde 3	0.0	0.0	0.0
PV Phase-in Proc	0.0	0.0	0.0
Subtotal	0.0	644.6	644.6
MAAC:			
SONGS 2,3 prCOD	819.2	0.0	-819.2
* SONGS 2,3 poCOD	0.0	52.6	52.6
Amort.Bal.Ac.	0.0	0.0	0.0
* Sec.463 (in GRC)	0.0	55.3	55.3
IMAAC: PVNGS-1,2	46.4	0.0	-46.4
OTHER OFFSETS:			
CLMAC	-5.8	-16.8	-11.0
Haz.Waste	0.0	0.0	0.0
ECAC Regular	1562.9	1562.9	0.0
AER	180.0	180.0	0.0
Uran.	76.8	76.8	0.0
Chvrn Bal Amort.	147.7	201.9	54.2
ERAM Amort.	-87.7	-87.7	0.0
IMAAC Amort.	0.0	50.2	50.2
SONGS-1 Memo Ac	0.0	87.6	87.6
Tax Act'87 refd	0.0	-44.9	-44.9
Res.3053-E	0.0	-3.6	-3.6
Decommg Taxes	0.0	-10.7	-10.7
Total (all above)	2739.5	2748.2	8.7
GRC:			
* Results of Oper.	2644.6	2588.7	-55.9
Other Revenues	57.5	57.5	0.0
Subtotal	2702.1	2646.2	-55.9
CPUC remb.fees	7.7	7.7	0.0
GRAND TOTAL	5449.3	5402.1	-47.2

Notes: * Amounts depend on adopted ROE.
** Based on adjusted sales of 64,500.3 GWH.

(End of Appendix E)

A 86-12-047

I 87-01-017

D 87-12-066

DECISION NO.______CASE NO.________APP. NO.______