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ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY for Authority to Decrease its Rates and Charges for Electric, and to Increase its Rates and Charges for Gas and Steam Service. (U-902-M)	Application 87-12-003 (Filed December 1, 1987)
Order Instituting Investigation into the rates, charges, and practices of the San Diego Gas & Electric Company.	I.88-01-006 (Filed January 13, 1988)

(See Decision 88-07-023 for appearances.)

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I N D E X

Subject

Introduction

Many of the revenue requirement items normally litigated in a general rate proceeding were agreed to in a Stipulation and Agreement and adopted in Decision (D.) 88-09-063. Additionally, cost of capital issues were bifurcated and consolidated with other energy utilities in a generic cost of capital proceeding. SDG&E's change in revenue requirement associated with our decision issued in that proceeding is reflected in Appendices A and C. Appendix C also lists a number of rate changes authorized in SDG&E's SONGS and ECAC proceedings. The revenue requirement changes contained in Appendix C are included in the adopted rates shown in Appendices F, G and H. These rates will become effective January, 1, 1989.

D.88-09-063 provided for revisions to the adopted Stipulation and Agreement as a result of more recent information. Accordingly, we will revise the Stipulation and Agreement for the following:

1. Nuclear Regulatory Commission (NRC) fees, ($72,000)

2 Labor and non-labor escalation rates

3 Electric Power Research Institute (EPRI) dues, ($96,000)

4 Women/minority business enterprise (W/MBE) program costs, $200,000.

Two studies were required by D.87-12-069, reliability of service and a comparison of rates with other utilities. While the reliability of service study was submitted, the comparison study has not been completed. SDG&E is working with Pacific Gas & Electric Company (PG&E) and Southern California Edison Company (Edison) on the comparison study and by letter dated September 28, 1988 notified Administrative Law Judge (ALJ) Ferraro that the study should be completed by June 1, 1989. This proceeding will remain open to receive the joint comparison study.

Procedural Background

On December 1, 1987 SDG&E filed A.87-12-003 requesting authority to reduce rates for its electric department and increase rates for its gas and steam departments for test year 1989. SDG&E

also requested attrition increases in 1990 and 1991 for all three departments. On January 7, 1988 a prehearing conference was held in San Diego. In March, 1988 there were two days of public participation hearings and between April and September, 1988 there were 21 days of evidentiary hearings.

Two interim decisions have been issued. D.88-07-023 replaced the $4.80/month residential customer charge for electric customers with a $5.00/month minimum bill and D.88-09-063 adopted the Stipulation and Agreement signed by SDG&E, Division of Ratepayer Advocates (DRA), Utility Consumers Action Network (UCAN), the City of San Diego, and Federal Executive Agencies (FEA) as resolution of most of the revenue requirement issues.

On June 14, 1988 a comparison exhibit was submitted which detailed the revenue requirement issues in the proceeding. An addendum to the comparison exhibit which addressed attrition issues was submitted on June 24, 1988. These items have been received as Exhibit 137.

<u>Comments</u>

In accordance with PU Section 311 the proposed decision of Administrative Law Judge Ferraro was mailed on November 18, 1988. Timely comments on the proposed decision were filed by the following parties: SDG&E, DRA, Independent Power Corporation (IPC), PG&E, and Edison. These comments have been reviewed and carefully considered by the Commission. Any changes required by the comments have been incorporated in the final decision.

<u>Conservation/Load Management Adjustment Clause (CLMAC)</u>

All expenses associated with conservation and load management programs are included in the adopted test year 1989 expenses. This will eliminate the need for CLMAC and requires the amortization of the current balance. SDG&E estimates that as of December 31, 1988 CLMAC will have overcollected electric revenues by $10.5 million and gas revenues by $4.0 million and recommends that the overcollections be amortized over three years, consistent with its general rate case cycle.

We will adopt SDG&E's recommendation and reduce its electric revenue requirement by $3.5 million annually and its gas revenue requirement by $1.3 million annually. In its 1990 attrition year filing SDG&E should amortize any difference between the estimated and actual CLMAC balance over two years.

Depreciation

Depreciation calculations as governed by DRA's (formerly Utilities Division) Standard Practice U-4: Determination of Straight-Line Remaining Life Accruals (U-4) have consistently been adopted by this Commission for ratemaking. U-4 provides a formalization of the theory of depreciation and the guidelines for performing the statistical analyses on which depreciation computations are based. An objective of this methodology is to recover a utility's original cost of depreciable fixed capital less net salvage value over the useful life of the asset. To achieve this objective the remaining life expectancy of depreciable plant must be periodically reviewed and when appropriate, adjusted. U-4 states:

> "Depreciation charges even in the simplest project should be re-examined from time to time. It is obvious that, until final retirement, those charges involve estimates of future life and salvage. . . . The remaining life method requires reappraisals and reviews of the estimates used from time to time." (U-4 at 42.)

SDG&E proposes that the remaining lives for 17 electric department plant accounts be adjusted by using a method referred to as QAU. This method was developed by SDG&E and adopted for the first time in its 1982 general rate case, D.93892. The QAU methodology has also been adopted in recent general rate cases for Edison and PG&E. Edison took a position in support of QAU in this proceeding.

DRA, FEA, UCAN, and the City of San Diego, collectively Opponents, oppose the use of QAU and as a result recommend a depreciation expense level which is $6.6 million lower than SDG&E's. UCAN, DRA, and the City of San Diego also recommend that three life extending programs be considered in developing the remaining lives for certain plant. This would lower SDG&E's requested depreciation expense by an additional $1.3 million.

SDG&E's Position

SDG&E states that QAU simply provides a rational structure for systematically evaluating the need to shorten depreciable plant life by formalizing adjustments that would be made in the absence of the QAU technique. To implement the QAU technique, SDG&E depreciation analysts interview SDG&E experts who are best informed concerning uncertainties (technological, economic, political, etc.) which are independent of past retirement experience.

The experts are first given explanations regarding the key parameters of the QAU technique and then asked to comment on new events that might occur which could shorten plant lives. During the interview the experts are asked to comment on when the events could occur, the portion of plant which is expected to be retired, and the time interval for and likelihood of the event. After the interviews the depreciation analysts transform the input from the experts into numerical values which are processed through the QAU formula to reduce the remaining lives of certain electric plant.

In support of QAU SDG&E lists the following benefits from its use:

1. Direct input from experts who know the most about uncertainties in the public utility industry.

2. An adjustment procedure for remaining lives that is clear and subject to objective review.

3. An exact and permanent record of the basis for making adjustments to remaining lives.

4. Increased awareness of further uncertainties for plant accounts by SDG&E's depreciation personnel.

In response to the criticism of other parties SDG&E argues that:

1. Although QAU only considers life shortening uncertainties, a rational technique could be developed for lengthening life expectancies.

2. While QAU does not eliminate the application of judgement to depreciation calculations, it provides a framework for including the opinion of experts.

3. It is willing to provide the necessary support for the assumptions developed from the QAU interviews.

4. QAU does not speed-up capital recovery, but only formalizes adjustments that would otherwise be made.

5. Concerns over the interview process are not unique to QAU. With or without QAU, it is appropriate for depreciation analysts to interview experts.

DRA's Position

QAU has been used by SDG&E in calculating its depreciation expense since its test year 1982 general rate case. In that and subsequent general rate cases, its use has effectively been unchallenged. Additionally, other California utilities have adopted QAU adjustments for calculating their depreciation expense. In all of these situations the use of QAU was done without challenge, in large measure due to the relatively insignificant sums then represented and the large number of issues requiring treatment in a general rate case.

Acceptance of QAU was explicitly done only once, in the test year 1982 SDG&E general rate case. No other jurisdiction has accepted QAU, although the matter is currently pending in an Edison proceeding before the Federal Energy Regulatory Commission (FERC).

In this proceeding DRA made an in-depth analysis of the QAU adjustment mechanism. As a result of its detailed examination DRA is opposed to SDG&E's QAU methodology and takes the position that there is no basis for applying an adjustment such as QAU until events have progressed to a point where they are impacting the remaining lives of plant. The basis for DRA's opposition is summarized below:

1. SDG&E's QAU process relies on gross speculation that is misleadingly labeled as judgement.

2. The data gathering method of SDG&E has no controls to ensure credibility or integrity of the information and is inherently flawed by ensuring bias in the survey process.

3. DRA was not able to evaluate the judgments relied upon by SDG&E, because of the anonymity of the interviewees.

4. QAU is a poor means of dealing with the problem of potential early obsolescence.

5. QAU forces current ratepayers to pay higher rates in anticipation of events that will only benefit future ratepayers.

DRA's major concern is that making judgments about the impact of uncertain events on remaining lives of utility plant is the height of speculation. By definition these events have not occurred. Additionally, SDG&E has no written documentation that shows the relative weight accorded the various events and has not provided an explanation of why the events were selected or how their probabilities of occurrence were determined. DRA also cites examples where double counting may exist and the time horizons in which the events could occur have remained unchanged since SDG&E's 1982 general rate case. Because of these problems, DRA believes that SDG&E's depreciation rates have been too high.

Finally, DRA recommends that the following maintenance programs which are expected to extend the lives of various plant and equipment be considered in setting the remaining lives for depreciation. These programs are:

1. Pole Butt Treatment - This involves chemically treating wood poles with an environmentally safe solution which kills insects and arrests decay. It is expected to increase the life expectancy of treated poles by five to ten years.

2. Underground Switch Maintenance Program - A one time program replacing switch legs and improving oil quality.

3. Padmount Painting Program - A new painting program to minimize rust and corrosion which will, according to SDG&E, extend the life of padmount transformer equipment by at least five years.

The adjustment to the remaining lives due to these programs decreases depreciation expense for test year 1989 by $1.2 million with QAU and $1.3 million without QAU.

<u>Edison's Position</u>

In its last three general rate case decisions Edison's adopted depreciation rates were developed using QAU. Edison strongly supports the continued use of QAU for the following reasons:.

1. QAU provides a systematic approach and quantifiable support for the application of judgment rather than an ad hoc approach.

2. QAU allows for expert input by personnel directly familiar with the particular plant involved rather than relying solely on the judgment of the depreciation analyst.

3. It is appropriate for DRA to investigate double-counting, but this is not a reason for eliminating QAU.

4. QAU helps to improve the forecast of remaining life by assigning a probability that a future event will occur.

5. The QAU interview process is used by Edison to obtain information about life lengthening events.

6. Remaining lives should take into consideration future events to assure that ratepayers pay for plant from which they benefit.

FEA's Position

FEA argues that SDG&E has maintained the anonymity of its interviewees and that this has prohibited DRA and other parties from testing the reasonableness of their judgment. In contrast, the depreciation analysts, who make determinations regarding depreciation in the absence of the QAU technique, are accountable for their judgments and know the impact of their decisions on both the depreciation expense and revenue requirements.

Finally, FEA points out that no other jurisdiction has adopted QAU, it is not supported by other depreciation experts, and SDG&E has not demonstrated that the accrual rates developed using QAU have been more appropriate than those developed without QAU.

City of San Diego's Position

The City of San Diego is also opposed to the use of QAU emphasizing that SDG&E's methodology results in a double counting and does not provide an opportunity to cross-examine the basis of the interviewees' judgment. The city of San Diego recommends that QAU not be adopted and that the life extension programs discussed earlier be reflected in calculating SDG&E's remaining lives for the affected plant.

UCAN's Position

UCAN endorses the position of DRA concerning the use of QAU and states that SDG&E's QAU methodology is contradictory and unacceptably subjective. Additionally, UCAN submitted testimony that the remaining lives for plant associated with the wood pole treatment, underground switch maintenance, and padmount transformer painting programs should be increased. If adjustments are not made for these three programs UCAN recommends that the cost of the programs be removed from the rate case.

Discussion

For ratemaking, we have consistently adopted a policy of using straight-line remaining life depreciation as detailed in U-4 for the computation of depreciation rates. Remaining life recovers the cost of the plant less net salvage value and depreciation reserve over the average remaining life of the class of plant. Depending on the information available to the analyst, average remaining life can increase or decrease to reflect past and expected retirements. This information is periodically updated by the analyst when computing the remaining life of the various plant categories.

A major factor in the development of remaining lives is the depreciation analyst's use of judgment. In fact, U-4 explicitly directs analysts to exercise judgment in performing their analyses. The primary information that a depreciation analyst relies on is mortality and other historic data. This is essentially recorded information on how long various types of plant (poles, transformers, meters, etc.) have remained in service prior to retirement. Retirements may be due to physical degradation, obsolescence, economic, and other causes. Analysts under U-4 are not limited to historical data. Information on product life from manufacturers or known changes in plant are also appropriate for analysts to consider.

SDG&E's QAU methodology expands the depreciation analyst's use of judgment. First, it provides the analyst with a structured approach to receive direct input from experts. Second, it identifies information on uncertain events, not reflected in recorded data, that would shorten the remaining lives of certain plant accounts. Finally, it adjusts the remaining lives based on the probability of these events occurring.

Opponents of SDG&E's QAU methodology are critical of both the process and the concept. While all parties agree that analysts should take into consideration the best information available, Opponents argue that the information, its source, and its effect should be clearly identified and available. Additionally, Opponents state that the concept of quantifying uncertainties is a contradiction and only events that affect plant lives should be considered.

We agree with these criticisms. Whatever method is used, depreciation analysts must clearly identify all information that adjusts average plant remaining lives and the source of the information. We also expect the analyst's workpapers to detail the weight given to each event and how it impacts the calculation of average plant remaining lives. Finally, the data gathering process should be impartial. SDG&E's methodology was only designed to receive input which would shorten life expectancies and as a result it is inherently biased.

On a brighter note, we applaud SDG&E's effort to formalize the input of experts in evaluating remaining lives of plant accounts. However, the credibility of SDG&E's interview process would be greatly enhanced if it were expanded to include experts outside the company.

This leaves us with the main issue: Should we adjust remaining lives for uncertain events that are not reflected in historic data? Uncertain is the key word in this question. Since no event can actually be guaranteed to occur, plant lives could not be estimated if the definition of uncertain were adhered to literally. Even our use of historical data to estimate the remaining lives of plant accounts does not ensure that past events will recur.

Our objective now, as in the past, is to use our best judgment after weighing all the pertinent information to arrive at a reasonable depreciation rate. A reasonable depreciation rate is one that allows a utility to recover its investment over the useful life of the asset. At some point during this process the depreciation analyst must use judgment to determine the usefulness of the available information. To do this the analyst must not only know the information, but also the basis for the information.

In SDG&E's QAU methodology the analyst applies judgment to develop the inputs to the QAU formula. The results of the QAU formula are used to adjust the remaining life of various plant accounts. This adjustment is in addition to the depreciation analyst's use of judgment to determine the average service lives of the plant accounts. Since remaining lives are derived from average service lives, a possibility for double counting the impact of future events is created. SDG&E believes this does not occur because the input to the QAU formula is based on events which are not considered in the determination of average service lives.

SDG&E's process requires the independent application of judgment twice in its depreciation study. First, it is used to reflect the impact of past and present events on retirements. Then, it is used to do the same for future events which could shorten plant lives. Finally, the record is unclear where in the depreciation study SDG&E recommends that judgment be applied for future events which could lengthen plant lives.

We are not convinced that SDG&E's methodology provides the best approach to the determination of remaining plant lives. While many models are used in the regulation of utilities, the assumptions used in these models are usually based on recorded data or forecasts developed from recorded data. SDG&E's QAU model assumptions are all speculative based on the opinion of experts. We do not believe it is appropriate to use a model with purely speculative assumptions for determining depreciation rates.

This does not mean that consideration of future events not reflected in historical data should be excluded, but that the depreciation analyst should consider all events which could affect plant lives at the same time and adjust average service lives accordingly. By doing this the interaction between historical, current, and future events can be considered in making adjustments.

Our rejection of SDG&E's QAU methodology is not intended to signal utilities that depreciation analysts should isolate themselves from the input of experts. On the contrary, we prefer a process which solicits information from experts, provides their identity, describes their input, and indicates how the information was applied.

For telecommunications utilities the Federal Communications Commission (FCC) represcribes depreciation rates at three-year intervals. A telecommunications utility first submits proposed changes, including adjustments to average service lives, to DRA and FCC staff. After a detailed review of the initial proposal any changes recommended by DRA and FCC staff are discussed in a joint meeting at which subject matter experts are heard. If agreement is reached, the utility and DRA jointly recommend that the agreed upon depreciation factors be adopted. If agreement can not be reached, the telecommunications utility must file an application requesting approval of its depreciation study. This process is referred to as represcription.

Since depreciation rates for energy utilities are determined on a three-year cycle in general rate proceedings, it seems reasonable to adopt a procedure similar to represcription for them. Accordingly, we will require depreciation workshops to be held in SDG&E's future general rate cases. The workshops should be conducted after DRA has issued a report which analyzes SDG&E's depreciation proposal. We encourage SDG&E to bring subject matter experts to the workshops to justify adjustments which differ from those shown in DRA's report. Additionally, all interested parties should be invited to attend and participate in the workshop. Differences which remain after the workshops are concluded should be addressed in the general rate case hearings.

This procedure should provide for a more open process with direct input from experts in areas of dispute. It is also consistent with the represcription procedure used for telecommunications utilities. Finally, other major energy utilities should explore the use of this procedure in their general rate proceedings.

In D.84-06-111 for Pacific Bell technical updates that provide for automatic adjustment of depreciation rates to account for changes in the composition of utility plant and relative growth or decline in depreciation reserve were first adopted. The purpose of the updates is to provide a smooth transition to new levels of depreciation expense which is more in line with the actual consumption of assets. This is necessary because changes due to represcription occur only once every three years. Since depreciation rates for major energy utilities are also reviewed on a three-year cycle, we believe it is equally appropriate to provide them with technical depreciation updates. Therefore, we will direct SDG&E and DRA to address the issue of technical depreciation updates in SDG&E's next general rate proceeding. We also invite other major energy utilities to address this issue in their general rate proceedings.

Finally, we will adopt the recommendation of UCAN, DRA, and the City of San Diego that three life extension programs should be considered in determining the average remaining lives for the affected plant. The adjustment to the remaining lives due to these programs decreases SDG&E's depreciation expense for test year 1989 by $1.3 million. The summary of earnings attached as Appendix A reflects this adjustment and the exclusion of QAU.

<u>W/MBE</u>

SDG&E, DRA, and American G.I. Forum, League of United Latin American Citizens, and Filipino American Political Association (Public Advocates) were the only parties to actively participate in W/MBE issues. DRA's participation principally addressed the costs for SDG&E's W/MBE program. These costs were included in the Stipulation and Agreement adopted in D.88-09-063. The Stipulation and Agreement also provides up to $200,000 for increased W/MBE Program Costs to reflect additional requirements

1. G.O. 156 did not identify Filipino-Americans as a separate category for goal setting.

2. A clearinghouse process was established by G.O. 156 for verification of W/MBEs.

3. Internal incentives will be expanded as a result of G.O. 156, if given an opportunity.

Our decisions in R.87-02-026 resulted in the adoption of G.O. 156, Rules Governing the Development of Programs to Increase Participation of Female and Minority Business Enterprises in Procurement of Contracts from Utilities as Required by Public Utilities Code Sections 8281-8285. Since most of the concerns raised by Public Advocates are addressed in G.O. 156, we will only discuss those which are not.

Public Advocates' recommendation to encourage W/MBE joint ventures and technical assistance in meeting financing and insurance requirements is compatible with G.O. 156. Additionally, in Edison's recent general rate case decision we stated:

> "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 join ventures and through assistance to F/MBEs in meeting financing and insurance coverage at rates competitive with Edison's non-F/MBE contractors." (D.87-12-066, p. 110.)

We believe this quote is equally applicable to SDG&E and will require SDG&E to encourage W/MBE joint ventures and provide technical assistance in meeting financing and insurance requirements at competitive rates. Finally, we will provide SDG&E the opportunity to establish management incentives to achieve the W/MBE goals in G.O. 156.

Attrition

With the exception of plant additions, SDG&E and DRA agree on the principles to be used in preparing SDG&E's attrition filings for years 1990 and 1991. No other party participated in attrition issues. The adopted attrition methodology is consistent with what was adopted for PG&E and Edison in their last general rate case decision.

Currently, the attrition mechanism adjusts the utility's revenue requirement to reflect changes from the adopted test year's plant and expenses. Test year expenses, adjusted for actual and estimated inflation rates, are used for the attrition years. These are updated to reflect changes in inflation rates at the time of the attrition filing. Except for SDG&E, attrition year plant additions are developed prospectively without later adjustment. SDG&E is the only utility which revises plant additions in its attrition filing for changes in inflation rates.

SDG&E proposes to estimate nuclear and non-nuclear plant additions for attrition using a four-year average of recorded and estimated plant additions. DRA agrees with SDG&E's methodology for non-nuclear plant, but recommends that projects which are non-recurring be removed from the average. For nuclear plant DRA recommends the use of Edison's budget in place of the four-year average.

The major projects which were excluded by DRA are the upgrading of the Moreneo compressor station, underground storage tank compliance, integrated voice and data network, and land for the corporate support center. DRA felt that projects of this kind would not occur in the attrition years and unfairly distort the four-year average. Certain large dollar items, considered non-recurring but not unusual, were left in the four-year average. One item was the district service center land. Since this occurs with sufficient frequency, DRA included it in the four-year average to compensate for projects which will occur in the attrition years, but are not included in the four-year average.

Finally, DRA recommends that under any circumstances the underground storage tank compliance project should be removed because it is a hazardous waste project. DRA argues that inclusion of hazardous waste projects in the four-year average would result in future hazardous waste projects reflected in rates twice, once in the four-year average of plant additions and again in separate hazardous waste filings.

SDG&E opposes DRA's exclusion of specific projects for the following reasons:

1. DRA's approach is inconsistent with the approved attrition methodology.

2. Specific projects for land acquisitions and voice radio network will be made in the attrition years.

3. DRA does not give consideration to non-recurring plant additions that would occur in the attrition years.

4. It is difficult to define a non-recurring project.

5. The dollars associated with the excluded projects are insignificant in relation to SDG&E's $250 million a year capital program.

6. DRA adjustments do not reflect the impact to deferred taxes and ad valorem taxes in the attrition years.

SDG&E proposes a four-year average of plant additions without reviewing the reasonableness of the data. While we are concerned with the appropriateness of the items which are excluded in estimating plant additions, we will not adopt SDG&E's simple average approach. We consider DRA's adjustments for projects that are not expected to occur in the attrition years or otherwise recovered in rates reasonable and will adopt its methodology.

DRA's methodology has been adopted for Edison and is a manageable alternative to the development and review of plant additions on a project by project basis. However, we will include the voice data network project in the four-year average of plant additions because it appears to reoccur in the attrition years. Since DRA has included the district service center land, we will not include an additional allowance for land acquisitions in the four-year average.

Our adopted attrition methodology takes into consideration SDG&E's concern that deferred and ad valorem taxes reflect the adopted level of plant additions. Since SDG&E's concern is addressed, no change is necessary due to our adoption of DRA's adjustments.

Although SDG&E maintains that a four-year average of plant additions should be used to estimate nuclear plant for the attrition years, it recognizes that nuclear plant additions have received unique treatment. SDG&E also acknowledges that DRA's proposal for handling nuclear plant additions is a fairly reasonable alternative.

Finally, SDG&E recommends an improvement to DRA's methodology, if adopted. Edison's most recent budget for nuclear plant additions should be used at the time of SDG&E's attrition filing. SDG&E believes this is necessary because nuclear plant additions are significantly affected by the refueling schedule.

We will adopt DRA's recommended use of Edison's budget for nuclear plant additions, which was subject to review by DRA during the proceeding, as providing the best estimate for the 1990 attrition year. For SDG&E's 1991 attrition year filing, we will reflect the estimate of nuclear plant additions adopted in Edison's test year 1991 general rate case decision. This will provide SDG&E

with the most recent forecast of nuclear plant additions which has been subject to review.

To avoid relitigating SONGS expenses we authorized SDG&E in D.87-12-066, Edison's test year 1988 general rate case decision, to use Edison's adopted level of SONGS expenses as the basis for SDG&E's 1989 test year and subsequent attrition filings. Litigating SONGS expenses in only one proceeding is an efficient and reasonable ratemaking approach. We will adopt Edison's authorized SONGS expenses for 1990 and 1991 as the basis for SDG&E's nuclear expenses for attrition years 1990 and 1991.

Finally, SDG&E believes that we should continue the practice of updating estimated plant additions for revised escalation rates. While SDG&E's current methodology is conceptually simple, the interaction of plant additions with depreciation and various taxes makes it cumbersome. Our adopted attrition methodology, which is consistent with PG&E's and Edison's, is simpler to implement and easier for parties to verify. Since our experience indicates that equally reliable results can be achieved with both procedures, we will not continue SDG&E's current practice of revising plant addition estimates in its attrition filings.

<u>Marginal Costs</u>

Marginal costs are the measure of change in a utility's total costs resulting from a change in output. A change in output is generally measured as a change in: (1) the level of energy over a period of time, (2) peak energy demand at an instant in time, and (3) customer access to the utility system. Marginal costs are used for revenue allocation, rate design and to evaluate the cost effectiveness of such things as conservation programs; research, development, and demonstration programs; and a utility's resource plan.

For a number of years we have moved toward revenue allocations based only on the utility's marginal costs. Recently this objective was accomplished in PG&E's and Edison's last general rate decisions and SDG&E's last ECAC decision. However, we expect that there will be a need from time to time to refine our adopted marginal cost methodology. Such is the case in this proceeding. While all the parties recommend the continued use of a marginal cost methodology, there are significant differences in their recommended approach for the development of marginal customer costs. Both the areas of agreement and the differences among the parties will be discussed below.

Marginal Energy Costs

SDG&E's marginal energy costs were not controversial. All parties agreed to use DRA's marginal energy cost estimates. These estimates, revised to reflect the appropriate revenue related tax factor, are shown in Appendix E.

Marginal Demand Costs

Marginal demand costs are divided into three categories: generation, transmission, and distribution. Although there is no disagreement among the parties concerning the methodology used to estimate marginal demand costs, there is a difference in the calculation of the customer component of distribution demand costs and primary distribution costs.

Distribution demand costs are comprised of a customer component and a demand component. The demand component is calculated as the residual of total marginal distribution demand costs less marginal customer costs. Because marginal distribution demand is calculated residually, differences are the direct result of the parties' calculation of marginal customer costs. This issue is discussed below.

For customers served at primary distribution, SDG&E had originally proposed to calculate marginal distribution demand costs as 90.05% of the marginal distribution demand costs for customers served at secondary distribution level. After DRA's marginal cost study recommended that the same unit costs be used for both services, SDG&E stipulated to DRA's position. UCAN opposed SDG&E's initial proposal stating that it: (1) reflects a 1986 cost of service study which considered some secondary distribution costs to be demand-related and (2) is inconsistent with the current positions of SDG&E and DRA that secondary distribution equipment does not have a demand-related component. Since SDG&E's distribution demand unit costs for primary and secondary service as shown in Exhibit 90 are the same amount, UCAN's concerns have been resolved.

The adopted marginal demand costs and a summary of marginal costs are shown in Appendix E.

Marginal Customer Costs

Introduction

Marginal customer costs incurred to establish and maintain customers on the electric system, include: (1) investments in distribution access equipment, (2) operation and maintenance cost relating to access equipment, and (3) customer accounting costs associated with meter-reading, billing, and bookkeeping functions. There are substantial differences among SDG&E, DRA, UCAN, and FEA with respect to these costs as represented by the following table:

	DRA	SDG&E	FEA	UCAN	
	(Dollars/Customer/Year)			Incremental/ Decremental	Incremental
Residential:	95.59	170.22	132.48	71.98	85.81
Schedule A:	163.42	238.05	169.38	123.78	151.90
Schedule AD:	531.03	605.67	447.05	406.97	501.85
Schedule AL:	3,196.57	3,271.21	1,757.55	2,151.17	2,954.61
Schedule A-6	11,897.21	11,971.84	8,554.60	11,647.02	12,959.48
Agricultural:	563.02	637.65	413.36	424.65	537.89
System Average:	115.31	189.95	143.58	86.73	104.46

The basic difference in the costs shown above results from the classification of certain distribution facilities as demand or customer-related and the methodology used to develop investment costs for customer access equipment. The more distribution facilities classified as demand related the lower the customer costs to small customers, i.e., residential and small commercial. Conversely, the more distribution facilities classified as customer related the lower the customer costs to large customers, i.e., industrial and large commercial.

The marginal customer costs presented by SDG&E reflect an escalation to 1989 dollars of the costs SDG&E presented in its 1987 (ECAC), A.87-07-009. These costs are comprised of three elements: (1) directly assignable costs derived by the transformers, services and meters (TSM) method, (2) non-dedicated distribution system access equipment costs or common distribution costs, and (3) customer accounting and collection costs. Each of these will be discussed below.

DRA recommends the methodology adopted by D.87-12-069, in SDG&E's A.87-07-009, with some modifications, as the best representation of marginal customer costs. These modifications exclude common distribution costs, and apply an unadjusted annual rental charge to the current cost of customer access equipment.

DRA is opposed to SDG&E's estimate of marginal customer costs because SDG&E's estimate of customer-related equipment is based on judgment and not subject to verification. Additionally, DRA criticizes SDG&E's approach due to its inconsistent use of the minimum intercept concept across the distribution system. DRA believes that if the minimum intercept concept was consistently applied, customer-related costs in the TSM component would be significantly lower.

Although DRA and SDG&E differ over which equipment is dedicated to providing access, they both support the use of a real or economic carrying charge rate for estimating annual charges on capitalized equipment. DRA states that:

> "The real economic carrying charge amortizes capital investments in a level stream of constant value dollars over the expected service life of capitalized equipment. It is a reasonable model for marginal cost pricing because the amortization of capital is directly related to the useful output of the asset, which in turn determines the revenues which flow to producers in a competitive market. For access equipment, the output and consequent market revenues associated with their use should not vary in real terms over time. Except under condition of significant oversupply, where producers in a competitive market would not receive sufficient returns to maintain the stock of productive equipment, the full economic carrying charge rate applied to current unit investment costs yields the theoretically correct marginal cost price." (DRA Opening Brief dated 7/8/88, pp. 11 and 12.)

UCAN identified a number of problems with SDG&E's calculations of costs for TSM investment, customer accounts, and customer collection. Additionally, UCAN proposes to reduce SDG&E's calculation of customer investments by 27% to reflect its incremental/decremental methodology.

FEA presented its own marginal cost study based on a minimum distribution system approach. This approach considers all costs of the distribution system which are required just to bring power to a customer to be customer-related. The remaining portion of the distribution system is considered demand-related. Because of inconsistencies that FEA believes are contained in UCAN's and DRA's studies, FEA recommends that its minimum distribution system approach be adopted. Alternatively, FEA recommends that, if UCAN's and DRA's proposed assignment of all TSM costs as customer-related is adopted, SDG&E's concept of separating the primary system into customer- and demand-related components should be adopted.

Directly Assignable Costs

Directly assignable costs are investments which are identified as relating to customer access. SDG&E, DRA, and UCAN derived these costs by the TSM method. For each customer class except large time-of-use (TOU) and agricultural, TSM costs were determined by work orders from the operating districts. Engineering estimates for typical customer installations were used to derive costs for the large TOU and agricultural classes.

UCAN had a considerable number of recommendations concerning the development of directly assignable costs. Three of these were agreed to by SDG&E: (1) TSM costs for residential and Schedule A should not reflect a contingency factor, (2) 4% should be used for purchasing and warehousing costs for transformers, and (3) a weighted average of single-family and multi-family units should be used to determine TSM costs for customers on schedule DR. UCAN's recommendations which were not agreed to are discussed below.

There are two issues concerning the weighting of single-family and multi-family units for determining TSM costs. First, UCAN recommends that the weighting should be based on incremental customers rather than DRA's use of average customers. Second, UCAN believes consideration should be given to cost-decreasing characteristics such as the number of overhead versus underground units and the number of coastal customers with lower usage.

For the single-family/multi-family DR schedule SDG&E agrees in principle with UCAN's position that a weighted average of single-family and multi-family units should be used to determine TSM costs. However, SDG&E recommends that DRA's calculation of 65.5% single-family units and 33.5% multi-family units based on test period housing stock be used. SDG&E argues that UCAN's weighted average of single-family and multi-family units does not reflect schedule DT (mobilehome) and DS (multi-family) customers. DRA recommends use of 17 units per customer for schedule DM, DS, and DT. DRA's estimates were unchallenged, and we will adopt DRA's estimates.

Since we are developing marginal customer costs for an existing system, it would be inappropriate to use a weighting of incremental customers, as suggested by UCAN. We will adopt DRA's weighted average of single-family and multi-family units. For its second recommendation, UCAN did not present a methodology or sound theoretical basis for reflecting the characteristics it identified as cost-decreasing. We will not adopt this recommendation.

UCAN claims that there is an inconsistency between the 129% labor overhead rate SDG&E used for meter installations and the 111% labor overhead rate used on work orders for customer costs. Additionally, UCAN argues that SDG&E did not explain the inconsistency and only one overhead factor should be in effect at a time. As a result, UCAN recommends that the 111% rate be used.

SDG&E disagrees that labor overhead associated with indirect labor should be reduced form 129% to 111% and provided an exhibit detailing the calculations of its 129% labor overhead rate. However, SDG&E did not give an explanation for the difference between the two labor overhead rates. Without this explanation we are unwilling to adopt the higher labor overhead rate. UCAN's recommended labor overhead rate of 111% will be adopted.

UCAN believes that SDG&E overestimated the cost of purchasing transformers and recommends that UCAN'S lower estimates developed from SDG&E's purchase contracts be used. SDG&E is opposed to UCAN's estimate of transformer costs and recommends that a moving average inventory price be used.

A moving average of inventory is an appropriate method for determining the plant investment associated with transformers being placed in service, but does not strictly adhere to marginal cost principles. Since SDG&E did not dispute the transformer costs represented by its purchase contracts, we will adopt these as representative of the incremental cost of transformers.

SDG&E calculated a real fixed rate of 10.38% which it used to annualize TSM investments. UCAN recommends a 9.78% rate.

This rate was calculated by excluding three FERC accounts which UCAN considers unrelated to TSM investments. DRA calculated a 10% rate after excluding two of the three FERC accounts UCAN questioned. DRA considers the third FERC account, which covers protective devices and capacitors, to be related to TSM investments and included it in its calculation. During the proceeding SDG&E changed its position and now supports DRA's 10% real fixed rate.

We find DRA's argument that protective devices and capacitors are related to TSM investments persuasive and will adopt its recommended real fixed rate of 10%.

<u>Common Distribution Costs</u>

The classification of common distribution costs as either demand or customer-related was a major area of controversy. SDG&E estimated the customer-related portion of common distribution costs using a proxy for the "minimum distribution system" method. This method assumes that 50% of non-energized facilities and 25% of energized facilities required to provide customers with access through the distribution system are customer-related.

In support of its methodology SDG&E argues that:

1. Although the estimates of common distribution costs are judgmental and not subject to independent verification, many marginal costs are not subject to precise calculation. Achieving a result that is approximately correct is superior to ignoring a marginal cost principle.

2. TSM costs are classified as customer related because they can be directly identified with facilities dedicated to serving individual customers.

3. The proxy for the "minimum distribution system" is intended to represent common distribution costs which are dedicated to the service of customers as distinguished from meeting their demands.

4. For the common distribution element of customer-related costs, data is taken from FERC accounts over a 12 year period in constant dollars then divided by the number of customers to derive a proxy for common distribution costs. SDG&E's methodology does not double count by taking a percentage of FERC accounts from any particular year or set of work orders.

Since UCAN, DRA, and SDG&E have accepted secondary distribution lines as a customer-related component of marginal customer costs, UCAN believes that only the TSM costs recommended by DRA should be included as customer costs. Additionally, UCAN opposes SDG&E's inclusion of common distribution costs because it: (1) results in double-counting of some costs, (2) is based on embedded cost data, and (3) allocates costs by number of customers rather than demand. Finally, UCAN states that Exhibit 89, which eliminates double-counting from SDG&E's common distribution costs, is not based on the same allocation percentages used in SDG&E's original testimony.

We prefer the approach of identifying specific equipment as access related and assigning the investment costs directly to the appropriate customer class. While there is not a clear line of distinction between demand and customer related equipment, we believe the TSM method provides us with the best approximation. Accordingly, we will treat the remaining common distribution costs as demand-related.

<u>Customer Accounting Costs</u>

SDG&E estimated customer accounting costs for the forecast period and then allocated them to customer classes using weighting factors for each FERC account. UCAN recommended three adjustments to the customer accounts and collections costs included in SDG&E's marginal cost study. First, UCAN identified a discrepancy between customer accounts and collections costs in SDG&E's marginal cost study and the costs in SDG&E's results of operation showing. UCAN acknowledges that this discrepancy was corrected by both SDG&E and DRA.

Second, UCAN maintains that SDG&E has failed to consider the significant differences in the cost of reading meters among various customer classes. UCAN recommends that meter reading weighting factors that SDG&E developed and used in the past be adopted in this proceeding.

Finally, UCAN states the Commission has a long-standing policy to exclude conservation and marketing programs from marginal customer costs and recommends that they be excluded in this proceeding.

In response to UCAN's proposed corrections, SDG&E states that:

1. The largest correction, which addresses the inconsistency between SDG&E's marginal cost calculation and the results of operation calculation, has been corrected in Exhibit 63-3-A.

2. No correction is warranted for conservation-related expenses and residential meter reading. Conservation expenses are customer-related and should be reflected in customer accounting costs. Reductions in residential meter reading costs are undocumented and should not be adopted.

Obviously there is a difference in the cost of reading meters for the various customer classes. Since SDG&E apparently developed weighting factors in the past which represented the cost differential of reading meters for each class, we will use these weights. UCAN is also correct that we have a long-standing policy of excluding conservation and marketing programs from marginal customer costs. SDG&E has not attempted to justify a change in this policy. We will adopt both UCAN adjustments for customer accounting costs.

Incremental/Decremental Marginal Customer Costs

UCAN states that one of the fundamental premises of marginal cost pricing is that it can simulate a competitive market where none exists. Ideally, UCAN would simulate a competitive market for determining the costs of customer access equipment by collecting customer investment costs through a hookup charge for new customers or through simulated purchases of access equipment by all customers. In this proceeding UCAN proposes an incremental/decremental methodology that reflects a hookup charge for new customers and decremental costs for existing customers. UCAN believes that this methodology, which reduces customer investments by 27%, provides a more accurate estimation of costs imposed by existing and new customers than the proposals of other parties.

Under UCAN's proposal hookup charges for new customers would be assigned to the appropriate customer class for revenue allocation. Once a hookup charge is collected through rates there would be no further revenue responsibility for that access equipment. The access equipment investment costs for existing customers would be based on the cost to the utility if the customers were to leave the system.

In response to DRA's rental market approach, UCAN argues that it does not properly reflect a fully competitive market in which customer ownership of access equipment would prevail because it is cheaper to buy equipment than rent it.

SDG&E is opposed to the UCAN's incremental/decremental approach to marginal customer costs as proposed by UCAN for the following reasons. UCAN's approach assumes that:

1. Customers would be able to buy new access equipment at an annual cost below SDG&E's charges.

2. Existing access equipment is worth less to customers than new equipment.

3. SDG&E would not sell new access equipment.

4. Customers would finance access equipment only at fixed interest rates. Renters are not taken into consideration.

5. Based on judgment, a 25% salvage value is appropriate for SDG&E's access equipment.

DRA believes the objective of marginal cost pricing is to simulate competitive market results and that UCAN's incremental/decremental method is not a market-related theory. In opposition to UCAN's method DRA argues that:

1. It has significant reservations concerning safety, liability, and general customer interest in an outright customer purchase option.

2. Most customers are likely to remain as renters of access equipment in the foreseeable future.

3. Its rental market approach would exclude residential customers who purchase access equipment. This is currently done for other customer classes.

4. It is extremely unlikely that competitive providers could furnish access equipment at only 25% of SDG&E's estimated costs. This is a basic assumption in UCAN's methodology.

UCAN agrees that DRA's rental market approach would result in prices that equal the incremental customer cost if it represents a truly competitive marketplace. UCAN argues that in a truly competitive market customers would have the option of purchasing or renting access equipment, but that DRA's approach only assumes a rental option. Because of the deductibility of mortgage and business interest, UCAN believes that purchasing equipment is cheaper than renting and that in a competitive market purchases would prevail and rentals would be scarce. Thus UCAN concludes that a rental market approach does not represent a competitive market and should not be used in determining marginal customer costs.

In evaluating UCAN's criticism, we conclude that its own proposal does not correctly represent the cost of customer ownership. We believe it is unrealistic to expect competitive providers of access equipment to be able to undercut SDG&E's investment costs by 75%. We are also not convinced that a substantial number of customers would choose to purchase this kind of equipment. Aside from potential operational and safety concerns, many customers would likely choose to rent rather than buy for convenience and reliability.

If expanded customer ownership is shown to be practical, DRA's proposal to exclude such customers from the allocation of access equipment is a logical and reasonable solution. This is currently the practice for industrial and large commercial customers which purchase access equipment.

Finally, we believe the most appropriate methodology for determining the cost of access equipment is DRA's rental market approach. We recognize that our rejection of the incremental/decremental methodology contradicts the discussion contained in D.86-08-083, PG&E's 1986 ECAC proceeding. However, the proceedings over the last two years have given us an opportunity to understand the marginal cost principles involved with marginal customer costs better than we did two years ago. Accordingly, it is now clear that the incremental/decremental methodology is not consistent with our marginal cost principles as discussed above.

Marginal Revenue Determinants

Marginal revenue determination is a critical aspect of the marginal cost and revenue allocation process. Marginal costs are multiplied by marginal revenue determinants to determine marginal cost revenues. These are the revenues the utility would collect if all customers were charged their marginal costs instead of rates adjusted for the utility's revenue requirement. Marginal revenue determinants are developed for energy, customer and demand. Marginal revenue determinants for demand are further divided into generation, transmission, and distribution. Most of the differences among the parties centered around marginal revenue determinants for demand. We will discuss each of the marginal revenue determinants below.

Marginal Energy Revenue Determinants

SDG&E and FEA agreed to DRA's marginal energy revenues, as shown in Exhibit 63. However, during the hearings DRA revised the marginal energy revenues in Exhibit 63 to reflect a revenue-related tax factor which was inadvertently omitted. We will adopt DRA's marginal energy revenues revised to reflect the appropriate revenue-related tax factor.

Marginal Demand Revenue Determinants

The parties do not agree on the appropriate marginal demand revenue determinants to be used for revenue allocation. There are four areas of disagreement: (1) annual demands versus demands by time period, (2) reliability adjustment for generation demand, (3) diversity factors for the residential and small commercial classes, and (4) demand loss factors.

SDG&E used load research data to determine demand levels by class and TOU period, and coincident and non-coincident non-diversified demands by voltage level. The weighting factors for each marginal demand revenue component were derived following the method used in the Edison general rate case decision, D.87-12-066. The annual marginal demand revenue component was calculated for each class by multiplying the appropriate TOU period demand by each marginal demand cost. The results were summed across all time periods and demand types for that class.

DRA's methodology differs from SDG&E's in that: (1) average annual demands are used instead of demands by TOU period, (2) a reliability adjustment is applied to generation demand, and (3) a diversity factor is used to determine transmission, and distribution demand. With the exception of distribution demand, UCAN adopted DRA's marginal revenue determinants to calculate its marginal cost revenues. FEA only took issue with DRA's and UCAN's transmission and distribution demands.

Except for DRA's reliability adjustment and diversity factor for residential class transmission and distribution demands, we will adopt DRA's methodology, weighting factors, and demand determinants for calculating marginal cost revenues. Below, each of the issues involving marginal revenue determinants is discussed.

<u>Annual Versus TOU Demand</u>

DRA asserts that although it is appropriate to calculate marginal energy costs by time periods, it is inappropriate to do so for marginal demand cost revenues. DRA states that investments in generation, transmission, and distribution systems do not vary by time period. Additionally, DRA claims that the use of time periods to calculate demands is unnecessary and would amount to sizing SDG&E's system for average demand. While FEA and UCAN support DRA's use of annual demands, SDG&E recommends that demand cost revenues be calculated by time period. We recognize that marginal demand costs by TOU period are used for rate design, however, SDG&E has not convinced us that they are also needed for revenue allocation. We will use annual demands to calculate marginal demand cost revenues.

<u>Generation Demand</u>

DRA calculated generation demand cost revenues by taking the sum of loss of load probability-weighted (LOLP-weighted) demands for each class and multiplying them by the generation level marginal costs. DRA states that a similar methodology was adopted in Edison's last general rate case decision. SDG&E is opposed to

DRA's use of LOLP-weighted demands. It states that DRA's LOLP-weighted generation demand of 1992 megawatts (MW) is too low. SDG&E and FEA recommend the use of a coincident peak. SDG&E based its coincident peak on the 1986 recorded system peak of 2376 MW. UCAN recommends the use of LOLP-weighted generation demand based on the 1989 forecasted demand of 2766 MW.

Consistent with the generation marginal demand cost methodology adopted for Edison and PG&E we will use a LOLP-weighted generation demand, however, in this proceeding DRA's generation demand is much lower than recorded 1986. From the record it is not clear why this occurred, but it could be a problem with the available data. Accordingly, we will scale up DRA's LOLP-weighted generation demands to the recorded system peak of 2376 MW.

Transmission and Distribution Demand

All parties used DRA's methodology for the calculation of transmission and distribution demands. DRA's methodology is based on the hypothesis that the demand seen by the transmission system is a weighted average of coincident and non-coincident demand for each rate class. Similarly, the demand seen by the distribution system is also a weighted average of these demands. The differences between the parties focused around: (1) weighting factors for calculating transmission and distribution demand and (2) coincident and non-coincident demands used for calculating transmission and distribution loads.

Although all parties used DRA's methodology for calculating weighting factors, SDG&E and FEA used different data in deriving their weighting factors. We will adopt weighting factors which are consistent with the adopted demand determinants.

SDG&E believes that the proper non-coincident demand to use for all classes is non-diversified. DRA uses non-diversified, non-coincident demand to measure the load placed on the distribution system by customers in all but the residential and small commercial classes. DRA uses diversified non-coincident demand for the residential class and an average of diversified and non-diversified, non-coincident demand for the small commercial class. FEA used an average of diversified and non-diversified demands for both the residential and small commercial classes, while UCAN essentially used DRA's methodology.

DRA believes that a diversified demand is appropriate for the residential and small commercial classes because the final line transformer serves multiple customers. While DRA was unable to acquire specific data from SDG&E concerning the number of residential customers served by each transformer, it assumed an average of 20 customers were connected to each transformer. DRA based its assumption on talking with load research experts and data from other utilities. Assuming 20 customers are connected to each transformer, DRA calculated a diversity factor of 25% of non-diversified, non-coincident residential load. A 25% diversity factor assumes that no more than 25% of the maximum load of all individual customers connected to any residential transformer will occur at the same time.

Although SDG&E did not provide data to support its argument that DRA's assumption of 20 customers connected to each transformer is too high, it asserts that fewer than 10 customers are likely to be connected to a new transformer. As a result, SDG&E considers DRA's 25% diversity factor to be unrealistic. Additionally, SDG&E states that its distribution planning manual instructs planning engineers to use a diversity factor between 55% and 75% when 10 customers are connected to one transformer. Finally, although UCAN did not develop a diversity factor, its witness testified that the appropriate diversity factor is probably between 50% and 75%.

Additionally, FEA takes exception to UCAN's and DRA's transmission and distribution demands. FEA states that the peak load on the transmission system must be equal to or greater than the system peak, but that DRA uses only 2,650 MW for transmission demand while test year 1989 peak demand is 2,778 MW. FEA also criticizes DRA's and UCAN's use of 3,385 MW and 3,174 MW, respectively, for distribution demand. FEA recommends a distribution demand of 4,400 MW based on the average substation peak which includes average class peaks and individual customer peaks. Since DRA's and UCAN's estimates do not reflect individual customer peaks, which play a major role in sizing various elements of the distribution system, FEA concluded that they do not appropriately represent distribution demand.

UCAN argues that: (1) FEA's demand allocators do not adequately reflect the diversity among classes with small customers, (2) FEA's witness conceded that the class non-coincident peak does not affect the design of the distribution system, and (3) SDG&E and FEA urge the use of the same method. Finally, UCAN concludes that DRA's method is reasonable.

We believe it is appropriate to consider a diversity factor for residential and small commercial classes. However, without data on the average number of customers served from each of SDG&E's transformers, we are unwilling to adopt DRA's 25% diversity factor. Based on SDG&E's planning manuals and UCAN's testimony, we consider a 50% diversity factor for the residential class reasonable for this proceeding. Since the only dispute with the diversity factor for the small commercial class was its use, we will adopt DRA's diversity factor for this class.

Demand Loss Factors

DRA pointed out that the demand loss factors used by SDG&E were less than the on-peak energy loss factors and in error. In response to DRA, SDG&E agreed to conduct a new study of demand and energy loss factors to address DRA's concerns.

Consistent Demand Determinants

Some parties are concerned that there may not be consistency among the demand determinants used for marginal cost, weighting factors for transmission and distribution demand, and marginal revenues. Although DRA, UCAN, and FEA agree that there should be consistency among the demand determinants, DRA and UCAN only appear to be concerned if a lack of consistency causes a significant difference in the final revenue allocation. We agree with DRA's and UCAN's position and will endeavor to use consistent demand determinants in the marginal cost and marginal revenue calculations.

<u>Marginal Customer Revenue Determinants</u>

SDG&E and DRA stipulated to the number of customers in each class and no other party took issue with their agreement. Differences in total marginal customer-related revenues are only due to differences in unit marginal customer-related costs. We will adopt SDG&E's and DRA's stipulation on the number of customers in each customer class.

<u>Revenue Allocation</u>

Revenue allocation is the process by which SDG&E's adopted revenue requirement is allocated to the various customer classes. In recent years we have followed a policy of using marginal cost principles in revenue allocation and as a guideline for rate design. Economic theory dictates that marginal cost pricing allows the customer to trade-off usage of electricity with consumption of other resources or to increase or decrease usage based on the incremental cost of producing electricity. Marginal cost pricing also provides equity in rates, by relating costs imposed on the electric system with the customers who are responsible for those costs.

Since revenues based on marginal costs are not usually equal to the utility's revenue requirement, a method must be used that allows us to reflect marginal cost principles while still collecting the authorized revenue requirement. The method used in recent years to reconcile marginal costs with revenue requirement is EPMC. This approach allocates revenues so that each class is an equal percent of its marginal cost revenues. This is referred to as full or 100% EPMC.

D.87-12-069 in SDG&E's most recent ECAC proceeding adopted EPMC with the constraint that each customer class receive a minimum 5% rate decrease. Although residential and agricultural revenues were below the EPMC allocation for their respective class, we lowered all rates in the context of a $141.2 million decrease. In that decision we stated:

> "We believe that SDG&E's rates must be restructured and moved towards marginal costs in a deliberate and careful manner. Our adopted revenue allocation makes significant movement towards the adopted marginal costs and allows time for the refinement of marginal cost studies in future proceedings." (p. 2, D.87-12-069.)

DRA and FEA recommend a full EPMC revenue allocation without constraints, while SDG&E and UCAN recommend a capped EPMC allocation. Below is a discussion of each party's recommendation for revenue allocation with the exception of street lighting. Revenue allocation for the street lighting class will be addressed in the rate design section.

<u>SDG&E's Position</u>

SDG&E's preferred revenue allocation which assumes a decrease in electric revenues of $49.4 million or 3.9% would decrease revenues to the residential class by $30.0 million or 5.4%. Other classes would be decreased by 0.9% for large TOU, 2.0% for very large TOU, 8.9% for agricultural and 3.9% for all others.

SDG&E also proposed a revenue allocation based on DRA's recommended decrease of $88.9 million. If DRA's $88.9 million decrease is adopted, SDG&E recommends decreases of 6.8% for residential, 8.1% for very large TOU, 12.1% for agricultural, and 7.1% for others.

SDG&E's guiding principles for placing constraints on an EPMC revenue allocation are as follows: (1) employ as few constraints as possible, (2) give all classes a decrease, and (3) for rate stability, change no class more than plus or minus 5% of the system average percent change (SAPC). Application of these principles provides for rate decreases from 2.0% to 8.9%, which SDG&E states allows for steady but moderate movement toward full EPMC rates.

DRA's Position

DRA recommends a full EPMC revenue allocation which it states is consistent with our general policy of marginal cost-based rates. DRA believes that SDG&E's method of determining caps for various rate classes is arbitrary because there is no consistency between SDG&E's recommended decreases for the residential class at different system average percent decreases.

FEA's Position

FEA supports the movement toward full EPMC revenue allocation, and opposes SDG&E's proposal because it does not result in significant movement toward this objective. FEA believes that full EPMC is substantially easier in this proceeding because there is an overall revenue decrease.

UCAN's Position

UCAN proposes an EPMC allocation capped at 5% above SAPC. Based on UCAN's revenue allocation the cap applies to rate schedules AD and AL. If the overall decrease is between 4% and 6%, UCAN would deviate from the 5% cap by recommending no rate change in classes where rate continuity can be provided.

Additionally, UCAN states that there is a higher value of service and outage costs to commercial and industrial customers and that this is not reflected through traditional EPMC methodology. Accordingly, UCAN recommends that the large customer classes be charged for higher generation reserve margins and greater distribution system costs.

Discussion

The adopted electric base rate decrease of $89.3 million plus $31.7 million from SDG&E's SONGS and ECAC proceedings affords us the opportunity to implement a full EPMC revenue allocation methodology. We believe DRA's and FEA's EPMC revenue allocation proposals are the only ones that are consistent with our goal of providing customers with rates based on the cost of providing electric service. Their methodology is consistent with our goal of full EPMC revenue allocation as stated in Edison's and PG&E's recent general rate case decisions and adopted for SDG&E in D.87-12-069.

The spread from the SAPC decrease of 10% using full EPMC revenue allocation, ranges from a 8% decrease for residential customers to an 19% decrease for agricultural customers. Since most customer classes are clustered within plus or minus 5% of SAPC and no class has a decrease greater than 19%, we will not cap our adopted EPMC revenue allocation.

We also will not adjust the adopted EPMC revenue allocation for UCAN's recommendation that large customer classes be charged for higher generation reserve margins and greater distribution system costs for the following reasons:

1. We are not convinced that SDG&E's generation reserve margins or its distribution system are designed to provide customer classes with varying degrees of reliability.

2. UCAN has not developed a methodology for implementing its recommendation.

3. UCAN's adjustment is not appropriate for revenue allocation and should be addressed in the calculation of marginal demand costs.

Our adopted revenue allocation by class is shown in Appendix D. It reflects the general rate case revenue decrease and the revenue changes from SDG&E's SONGS and ECAC proceedings as shown in Appendix C.

Electric Rate Design

The following sections will discuss residential, commercial, industrial, agricultural, and street lighting rate design issues. For these classes the most heavily contested matters were rate schedules AD, AL-TOU, and A6-TOU, SDG&E's power factor adjustment, standby service, and street lighting.

D.88-07-023, dated July 11, 1988, replaced the $4.80 customer charge for residential customers with a $5.00 minimum charge and included the minimum bill in the baseline rate calculation. This matter will not be readdressed in this decision. The realignment of baseline and non-baseline residential rates in compliance with Senate Bill (SB) 987 (Ch. 212, Stats. 1988) is being addressed in Order Instituting Investigation (I.) 88-07-009 and is not at issue in this proceeding. Our adopted gas and electric residential rates reflect D.88-10-062 in I.88-07-009. The two-month undercollection of electric rates authorized in that proceeding is terminated effective with this decision.

Residential

While SDG&E's application contained a number of controversial proposals, SDG&E has either withdrawn its proposals or the parties have reached agreement on all but two items; baseline allowances and an increase in the returned check charge.

The only disagreement concerning baseline allowances is DRA's recommended continued phase-in to capture changes in average aggregate consumption. This procedure was adopted in SDG&E's last general rate case and DRA believes that Public Utilities Code (PU) § 739 requires its continuation. SDG&E argues that changes in baseline allowances will create an upward pressure on residential bills and, if changes are adopted, they should not be implemented until May 1, 1989, when seasonal baseline changes occur.

We agree with DRA that continued phase-in of electric baseline allowances meets the requirements of PU § 739 and we will adopt its recommendation. Baseline quantities will be reduced over a one to three-year period starting May 1, 1989. The adopted baseline allowances are shown in Appendix F.

The second issue is SDG&E's request to increase the current charge of $6 for a customer's returned check to $10. SDG&E based its request on bank charges which make up 59% of SDG&E's proposed $10 charge, the cost of processing, collection, and preparation of checks to be redeemed; and the cost of key punching for redeemed checks, materials, and postage.

UCAN opposes an increase in the charge for returned checks stating that SDG&E: (1) did not justify which costs have increased since the $6 charge was implemented, (2) did not identify what measures it has taken to reduce bank fees, and (3) may not monitor returned check policies properly.

Although SDG&E has provided an itemized list of the items which comprise its returned check charge, SDG&E has failed to provide convincing evidence that it is unable to negotiate lower bank fees for returned checks. Without assurance that lower bank fees are unattainable we can not be certain that an increase in the returned check charge is reasonable. We will not approve an increase in the returned check charge.

The agreements among the parties on the following matters appear reasonable and will be adopted:

1. SDG&E, WMA, and DRA agree that the discount for mobilehome parks on schedule DT should be $9.50/unit/month or $0.312 on a daily basis.

2. SDG&E and DRA agree that the discount for apartment buildings on schedule DS should be $4.04/apartment/month or $0.110 on a daily basis.

3. DRA, SDG&E, and UCAN agree with the DR-TOU rate design in Exhibit 96.

4. DRA agrees with SDG&E's proposal for experimental schedules DA-TOU and DU-TOU. These schedules are designed in relation to schedule DR-TOU with a 2:1 peak to off-peak ratio.

5. SDG&E has withdrawn the following residential rate design proposals: (1) late payment charge, (2) telephone charge with respect to bill collections, (3) customer charge, and (4) reconnection charge for the period when service is disconnected.

For the reconnection charge SDG&E had proposed to require a customer who leaves and returns to the system within a short period to pay the customer charge that would have been assessed if the customer had remained on the system. Center for Public Interest Law (CPIL) mailed testimony to all parties, except SDG&E, opposing SDG&E's proposal on April 15, 1988. SDG&E was hand delivered CPIL's testimony on April 25, 1988. On April 27, 1988 SDG&E recommended that the customer charge be eliminated for residential customers and withdrew its proposal to to assess customer charges for the time customers were off the system.

Small and Medium Commercial

The principal small and medium commercial schedules are A and AD. No structural changes are proposed for schedule A. Schedule AD was closed to new customers on July 1, 1987. Existing customers on this schedule have the option to remain on the schedule or move to the AL-TOU schedule. AL-TOU is a time-of-use rate schedule with rates which more closely reflect SDG&E's costs.

SDG&E proposes to modify the AD schedule by establishing a two tier declining block energy rate. The first tier rate is charged for the first 300 kilowatt (kW) hours consumption per kW of demand. The lower second tier is charged for usage in excess of that amount. SDG&E has designed the energy rates for this schedule to be similar to Edison's GS-2 schedule, which serves equivalent customers.

SDG&E makes this two tier AD energy rate proposal for the following reasons: First, it provides an incentive for customers to improve their load factors by controlling their demand. Second, the rate structure recognizes the level of customer demands placed on the system. Third, it emulates TOU rates without the expense of TOU meters. Fourth, it brings the tail block or tier II rate closer to, but not below, marginal cost.

In response to concerns expressed by other parties, SDG&E argues that: (1) its proposal will not increase energy consumption, because there is no ratchet provision, and (2) standby rates should only be available to TOU customers, but any customer with a demand above 20 kW can move to the AL-TOU rate schedule. Finally, SDG&E states that DRA's proposal is an acceptable alternative, if the two tiered energy rate structure is not adopted.

DRA recommends that the monthly demand charge on the AD schedule be increased from $5.00/kW to $5.50/kW to reflect marginal capacity costs more closely. DRA is opposed to SDG&E's two-tiered proposal, because it cannot reconcile SDG&E's declining block rates with cost-based rate design principles. Although SDG&E's rate design purports to collect capacity costs in higher tier I rates, DRA believes that the customer perceives declining block rates as a signal that the more energy used the less it costs.

In addition to DRA, IPC, Department of General Services of the State of California (General Services), Small Cogenerators of California (SCC), Poway Unified School District (Poway), San Diego Mineral Products Industry Coalition, and UCAN are opposed to SDG&E's declining block energy rates. Many of the concerns of these parties are similar.

Generally, they argue that:

1. Two-tiered rate designs are not in conformance with cost-based rate design principles.

2. Declining block rate structures are inconsistent with conservation policies.

3. AD customers which take all their energy off-peak would not be able to emulate TOU rates.

4. Lowering the effective rate for higher load factor customers will discourage migration to a TOU rate schedule.

5. SDG&E's AD schedule is not cost-based.

6. SDG&E's proposal will have a significant adverse impact on the economics for small scale cogeneration.

These parties are also concerned with DRA's proposal to increase the demand charge on the AD schedule, because: (1) many AD customers have low load factors and will see overall rate increases, and (2) the AL-TOU schedule offers no relief for these customers from increased rates. Finally, IPC recommended that, if a declining block rate structure is adopted, a special condition be added that allows customers which have the ability to self-generate to displace the higher, first-tier rate.

Although we support SDG&E's rate design principles for its two-tier AD rate, we consider its proposal inconsistent with them. SDG&E's proposal would create an inequity for AD customers which use more off-peak energy than the schedule's average and/or do not have second tier usage. This occurs because greater off-peak usage for these customers will not result in the emulation of TOU rates, and customers with only first tier usage will not have their incremental consumption priced at marginal cost. These inequities coupled with the concerns expressed by the parties are sufficient justification for not approving SDG&E's proposed changes to the AD rate schedule.

DRA states that its proposal to raise the AD demand charge from $5.00/kW to $5.50/kW, while not cost-based, moves in that direction. Since this is consistent with our objective of cost-based rates, we will adopt DRA's recommended increase in the demand charge for the AD schedule.

Finally, IPC recommends that all schedule A and AD customers have the option of TOU rates. Since SDG&E's witness testified that it was reasonable to provide a TOU option to these customers, we will allow schedule A and AD customers to move to a TOU schedule.

<u>Large Commercial/Industrial</u>

<u>AL-TOU and A6-TOU</u>

D.87-12-069 in SDG&E's 1987 ECAC proceeding adopted major changes for commercial and industrial customers served under rate schedules AL-TOU and A6-TOU. These changes, which provide for higher demand charges and lower energy rates, were the result of a stipulation in that proceeding.

The AL-TOU tariff consists of a customer charge, a non-coincident or non-time-related demand charge subject to a 50% ratchet, summer and winter peak demand charges, and energy charges differentiated by voltage levels for summer and winter. A6-TOU is a variation of AL-TOU. It includes the same non-coincident demand and energy charges, but a higher customer charge and higher peak demand charges for summer and winter to reflect customer demands at the time of each month's system peak. A rate limiter of $0.16/kWh also applies to both schedules. The stipulation referenced above included two levels of demand charges. D.87-12-069 adopted the lower level stating:

> "We adopt the lower set of demand charges proposed by all parties other than SDG&E because we prefer to move gradually towards the complete recovery of SDG&E's estimated fixed costs in fixed charges. These costs will be more closely examined in the general rate case." (p. 26, D.87-12-069.)

SDG&E requests that the higher level of demand charges contained in the stipulation be adopted, because the AL-TOU and A6-TOU schedules recover less than the marginal costs associated with those services. Additionally, SDG&E recommends that the energy rates be derived using the same model employed in the stipulation. No changes are recommended by SDG&E or other parties to the rate limiter or ratchet percentage.

DRA states that its AL-TOU and A6-TOU rate design including the relationships between on-, mid-, and off-peak energy rates maintains the structure adopted in D.87-12-069. DRA argues that an increase in demand charges is unwarranted because marginal capacity costs are less than those used in the AL-TOU and A6-TOU negotiations.

FEA supports DRA's position stating that D.87-12-069 significantly increased the demand charges for these rate schedules and introduced a new maximum demand charge. Although FEA recognizes that additional movement is necessary to fully implement EPMC at the schedule level, it recommends maintaining the current level of demand charges and decreasing the energy charges to reflect the decrease in revenue requirement.

General Services, while not a signatory, did support the stipulation adopted in D.87-12-069. General Services states that its support for the stipulation was based on a revenue reduction of between $63 and $83 million, but a decrease of $141.2 million was adopted. Because of the amount of the decrease adopted in D.87-12-069 and the possibility of a significant decrease in this proceeding, General Services recommends a proportionate decrease in demand and energy charges.

SCC also recommends a proportionate reduction in demand and energy charges. SCC believes this will avoid peak-clipping and allow lower load factor customers.

Finally, Poway recommends a change from the on-peak period of 11:00 a.m. to 6:00 p.m. in summer to 12:00 noon to

6:00 p.m. Poway states that the current on-peak summer period causes a financial hardship on school districts which normally end summer classes by 12:00 noon, but pay on-peak demand charges as if they operated during the entire on-peak period. As a result of Poway's concerns DRA and SDG&E have addressed this issue in more detail in SDG&E's current ECAC proceeding A.88-07-003. We will defer resolution of this matter to that proceeding.

Since considerable movement toward cost-based demand charges was made in D.87-12-069, we are reluctant to make additional changes now. We believe DRA's proposal of only adjusting energy charges to reflect changes in revenue requirement, which is supported by FEA, is a more reasonable approach to follow. This will allow continued, but moderate, movement toward cost-based rates.

We also consider it more appropriate to maintain the current relationship of the off-, mid-, and on-peak energy rates than use SDG&E's model which developed this relationship for the stipulation. While the parties to the stipulation may be aware of the workings of the model, most commercial and industrial customers are not. Maintaining the existing relationships should foster a clearer understanding and increase the acceptance of the adopted rates.

AO-TOU and AO6-TOU

AO-TOU and AO6-TOU are optional rate schedules which were closed to new customers as of July 1, 1988. SDG&E proposes that the customer and demand charges for these schedules be maintained at their current levels and the energy rates for each time period be reduced by an equal percent. No party opposes SDG&E's proposal.

We will adopt SDG&E's recommendation for the AO-TOU and AO6-TOU schedules. Since these were established as optional schedules in 1986 and are closed to new customers, we will require SDG&E to address their continued appropriateness in its next general rate proceeding. We will also require SDG&E, after its rate design exhibits are filed in the next general rate proceeding, to notify all customers on these schedules that the continuation of the schedules will be an issue in the proceeding.

Interruptible Service

Interruptible service schedules provide customers with a credit for interruptible demand that is in excess of their contracted level of firm service. These credits are based on schedule AL-TOU peak period demand charges. DRA and SDG&E agree that the interruptible credits should be revised to reflect changes in the demand structure of the AL-TOU schedule. SDG&E proposes to modify the credits by maintaining the relationship between the credits and the on-peak demand charges. DRA contends that the credits should be based on SDG&E's marginal capacity costs because demand charges may contain more than coincident capacity costs.

Although there is only a small difference between DRA's and SDG&E's recommended interruptible credits, we conceptually prefer DRA's approach and will adopt its methodology.

AE-1, R-TOU-1, and R-TOU-2

AE-1, R-TOU-1, and R-TOU-2 are experimental real time pricing schedules established in 1986 with a termination date of January 1, 1992. The structure of these rate schedules differs from other TOU rates in that on-peak charges only take effect when the system load reaches a predetermined level. The predetermined level or trigger point is adjusted annually by an advice letter filing.

SDG&E proposes to retain the existing rate structure and adjust only the mid- and off-peak energy rates. Although previous adjustments were not always consistent with the originally adopted design philosophy, SDG&E proposes to maintain the original philosophy by reducing the mid- and off-peak energy rates and equating the off-peak energy rates for the three schedules.

To maintain these schedules as viable and cost-effective alternatives, DRA recommends three adjustments to the rate structure. First, the mid-peak demand charge should be replaced by the maximum demand charge adopted for AL-TOU and A6-TOU. Second, the on-peak energy rate on AE-1 should be reduced significantly to accurately reflect marginal costs. Finally, the contract minimum demand charge should be reduced in response to changes in marginal capacity costs.

DRA argues that these rate schedules were designed to test real time pricing using the AL-TOU and A6-TOU rate structures that existed at the time. Since AL-TOU and A6-TOU underwent major changes in D.87-12-069, DRA believes that the real time pricing schedules should be revised to reflect the adopted changes.

Additionally, DRA recommends that customers on AE-1, R-TOU-1, and R-TOU-2 be permitted to switch schedules without restriction until July 1, 1989 and that the expiration date for these schedules be extended until January 1, 1993. This would: (1) allow for review of these schedules in SDG&E's next general rate proceeding, (2) provide customers the 12-month notice of termination called for in special condition 14, and (3) permit customers to react to recent and proposed rate changes.

While there is no price certainty implied in these rate schedules, we believe it is reasonable for customers to expect some consistency in the design criteria during the experiment. However, we agree with DRA that real time pricing schedules should reflect the rate structure of AL-TOU and A6-TOU, otherwise it would be unclear whether customer actions were influenced by the existing rate structure or real time pricing. Accordingly, AE-1, R-TOU-1, and R-TOU-2 will be closed to new customers on the effective date of this decision. DRA's recommendation to reflect the rate structure changes to schedules AL-TOU and A6-TOU will be adopted for establishing new real time pricing schedules.

<u>Power Factor Adjustment</u>

SDG&E is currently authorized to assess customers an extra charge if they operate equipment at a low power factor. Such equipment uses reactive power, measured in kilovars (kVARs), and requires SDG&E to install capacitors to maintain system capacity. Although SDG&E's rate schedules allow a charge of $0.21/kVAR/month when a customer's power factor is below 75% of their kilowatt demand, its electric rule 2(G) authorizes a charge for power factors below 90%.

SDG&E proposes to require customers on schedules AD, AL-TOU, A6-TOU, AE-1, R-TOU-1, R-TOU-2, and PA-T-1 with demands which have exceeded 300 kW in the last 12 months to maintain a minimum power factor of 90% at their own expense. If the customer fails to install the necessary equipment, SDG&E will install it at the customer's expense. Based on 1987 costs for this equipment, SDG&E proposes to increase the charge to $0.28/kVAR/month. SDG&E states that high reactive demands are not imposed by all customers and only customers which use kVARs should pay for kVARs.

DRA has reviewed SDG&E's requested changes to the power factor adjustment and the basis for the $0.28/kVAR/month charge and supports SDG&E's proposal. However, DRA is concerned that the treatment of the revenues from this charge was not addressed and recommends that they be considered in the current 3R's proceeding I.86-10-001.

UCAN argues that SDG&E has not provided an estimate of the revenue which its power factor charge would generate or how such revenue would be treated. UCAN recommends that SDG&E's proposal be rejected or, alternatively, any power factor revenues be tracked and used to offset expenses.

General Services states that SDG&E's proposed change in its power factor charge should be rejected. General Services makes this recommendation based on the lack of evidence to indicate there is a reactive power problem and the failure of SDG&E to estimate the amount of money the charge would generate. If a 90% power factor charge is adopted, General Services recommends that:

1. Implementation be delayed by six months to permit customers the opportunity to correct their own power factors.

2. Revenues be estimated and credited to each affected class or treated like standby revenues.

3. Customers be paid for power factors above 90%.

4. The lowest cost capacitors be used to develop a reactive charge.

SCC recommends rejection of SDG&E's power factor proposal to avoid discrimination against self-generation facilities.

We agree with SDG&E that customers with high reactive demands should pay for the kVARs they use, but SDG&E has not adequately demonstrated that it used the least cost equipment to develop its reactive charge. Without adequate support we will not increase SDG&E's present per kVAR charge.

Since most customers are not aware of SDG&E's present reactive charge, we will allow them six months to correct their power factors before being assessed the kVAR charge. To provide consistent treatment for special charges, revenues generated by the kVAR charge will be recorded in the same manner as standby revenues.

Finally, General Services has not sufficiently supported its claim that customers with high power factors benefit SDG&E's electric system. Accordingly, we will not adopt General Services recommendation that SDG&E pay customers with power factors above 90%. With the above modifications, we will adopt SDG&E's power factor proposal.

Standby Service

Rate schedules S and S-I provide standby service to demand-metered customers where SDG&E does not supply all or part of their regular electric requirements. These schedules were substantially modified by D.87-12-069 to reflect changes in the

AL-TOU schedule. Under schedule S, 80% of the contracted maximum demand is billed at the AL-TOU non-coincident demand charge. Schedule S-I has no associated charge, is limited to customers with demands exceeding 500 kW, and does not require SDG&E to provide service when its system is at full capacity. Under the current structure, standby customers which take energy during on-peak hours pay regular on-peak demand charges and associated energy rates, subject to a rate limiter of $0.67/kilowatt hour (kWh) in the summer and $0.26/kWh in the winter.

SDG&E believes more time is needed to acclimate customers to the present rate structure for standby service and does not recommend any changes. However, SDG&E does propose two new special conditions. First, SDG&E requests the option of providing standby service only to customers taking service through a single meter. This condition is intended to prevent arbitrage, a customer could take standby service during off-peak periods under AL-TOU and on-peak service through another meter on a different schedule. Second, SDG&E requests that standby service for customers with contract capacity exceeding 20 MW be provided by a Commission-approved contract. Such contracts, SDG&E argues, would provide the time and certainty needed to prepare for large standby service.

DRA proposes that the current rate structure be replaced by an on-going reservation charge equal to 2% of the coincident or on-peak demand charge applied to contracted standby demand. Additionally, when customers take service for forced outages, the on-peak demand charge would apply, but it would be prorated daily.

In response to DRA's proposal SDG&E argues that:

1. Prorating the on-peak standby charge does not compensate SDG&E for the cost of the facilities it must have available.

2. It is unlikely that standby customers would be able to provide same day notice of forced outages as required by DRA's proposal.

3. Standby service which is billed by hand would become more complicated.

FEA supports DRA's standby proposal, but recommends that customers only pay the greater of the prorated on-peak demand charge or the 2% reservation charge. FEA states that DRA's reservation charge is justified on the grounds that standby customers have different load characteristics than full requirements customers. FEA also contends that there should be no limitation on size regarding a cost-based standby rate and customers with multiple meters should be allowed to take standby service if all service is under one schedule.

General Services also supports DRA's proposal, but recommends four changes. First, the daily on-peak demand charge should be prorated on an hourly basis. Second, rate limiters should be retained. Third, the 2% reservation charge should be credited to any on-peak demand charges incurred during the month. Finally, AD customers should be allowed to take standby service and receive a credit for non-coincident demand charges on contracted standby load. Additionally, General Services suggests that a rate limiter be created for AD customers taking standby service.

SCC recommends that DRA's proposed standby rate structure be adopted with the retention of rate limiters and a provision for AD customers to take standby service.

IPC proposes a standby rate based on the marginal costs of facilities to serve all loads discounted to reflect the expected forced outage rate of self-generation facilities. The discount represents the probability that the standby service will be needed. This approach was developed by IPC to insure that standby customers are charged based on their use, not their potential for use.

IPC contends that a standby load can be expected to appear on the utility system randomly, during any time period and any season, and the forced outage rate measures the probability of this occurrence. IPC equates its methodology with that used to set rates for full requirements customers. Since all potential loads for full requirements customers do not occur on the utility system simultaneously, their rates are based on peak loads, which are a percentage of all potential loads. Similarly, IPC believes that standby rates should be based on forced outage rates, which are a percentage of the contracted standby loads.

IPC uses the California Energy Commission staff's forced outage rate for gas-fired cogeneration projects of 9% as representative of the self-generators in SDG&E's service territory. The 9% factor is multiplied by the adopted monthly marginal costs for generation, transmission, and distribution to derive the monthly per kW charge for standby service. The generation costs include a 15% reserve margin to reflect SDG&E's system reliability. Using the marginal costs proposed by DRA this method produces a monthly standby charge of $1.40/kW.

Under IPC's proposal standby customers would pay $1.40/kW/month whether or not service is taken. Standby customers that take service would also pay the energy charges from the rate schedule that would otherwise apply. No additional demand charges would be required, because all fixed costs that are recovered in the demand charges are included in the monthly standby rate.

Discussion

In D.86-12-091 for PG&E we established a policy for standby service that has been used as a guide to establish Edison's and SDG&E's current standby rates. That policy states that when standby customers take service, they impose costs in the same manner as full requirements customers, and should be charged the same rates. For periods when service is not taken, standby customers should pay the cost of customer-related services and dedicated facilities.

DRA's proposal with a 2% reservation charge is not consistent with this policy. First, the 2% charge is not related to facilities that are dedicated to standby customers. Second, when standby customers take service they would only be required to pay a daily proration of the on-peak demand charge compared to an entire month for full requirements customers. We consider it inequitable to provide standby customers with daily proration without providing it to full requirements customers.

IPC recommends a new approach for developing standby charges which, except for the concerns expressed below, appears to be a fundamentally sound methodology. As with DRA's proposal, IPC's methodology does not recognize that certain facilities are dedicated to serve standby customers and assumes that all transmission and distribution facilities are fully diversified. For generation costs which are recovered in coincident demand charges, IPC's approach indirectly results in a proration of on-peak demand charges. We believe an appropriate standby charge must address both of these concerns. In its next general rate case filing SDG&E should provide sufficient data to permit the determination of facilities dedicated to standby service including transmission and distribution facilities that are not fully diversified.

We also disagree with SDG&E's two proposed special conditions. First, customers should not be excluded from standby service because they take service from more than one meter. To avoid the possibility of arbitrage we will require that standby customers take all service under the same rate schedule. Second, SDG&E has not provided adequate justification for requiring a Commission-approved contract before customers with contract capacity exceeding 20 MW can receive standby service.

Finally, we will maintain the existing standby rate structure as the best representation of our standby policy at this time. Additionally, we see no reason why AD customers which elect standby service should be treated differently than TOU customers on standby service. Accordingly, as recommended by General Services, AD customers will be allowed to take standby service and receive a credit for non-coincident demand charges on their contracted standby load. Although the AD schedule incorporates on-peak demand charges in the energy rates, which simulates a rate limiter, we will apply the current standby rate limiter to establish an average rate ceiling for AD customers.

In DRA's and IPC's comments reference is made to the need for differentiating standby service by type of service; backup, maintenance, and supplementary. We disagree with these comments. We believe our adopted standby rate design with rate limiters to minimize bill impacts is consistent with the rates charged other customers and conforms to the FERC rules implementing the Public Utility Regulatory Policy Act of 1978.

PG and PG-QF

PG-QF was designed for cogeneration customers with output of 100 kW or less. D.87-12-069 closed this schedule to new cogeneration facilities above 20 kW by June 30, 1989. PG is an experimental schedule available to customers with generation facilities connected in parallel to SDG&E's system where no other schedule is available. Customers under either schedule currently pay no standby charge and are allowed to credit excess electricity produced against consumption during other periods. Under PG-QF excess generation is purchased by SDG&E at its current standard price offer.

SDG&E recommends that as of July 1, 1989 the energy netting provision of PG be closed to all customers and the schedule be closed to new customers. SDG&E claims that the lack of standby charges and the energy netting provision allows customers on these schedules to avoid paying the full cost of service.

SCC requests that the intended closure of PG-QF by D.87-12-069 be made clear. SCC argues that D.87-12-069 closed PG-QF only to new customers above 20 kW as of June 30, 1989 and that existing customers, on the schedule prior to that date, retained the right to credit excess electricity produced against consumption during other periods. If a definite date is desired for complete elimination of the energy netting provision, SCC suggests 10 years would provide the length of time necessary to retire the financing on cogeneration projects. No party opposed SCC's request to clarify D.87-12-069.

Since there appears to be no opposition to SDG&E's proposal for schedule PG, we will close PG to new customers and eliminate the energy netting provision. We also reaffirm the intent of D.87-12-069 to close schedule PG-QF only to new customers with generation facilities above 20 kW and to eliminate the energy netting provision only to new customers by June 30, 1989. For customers on PG-QF prior to June 30, 1989 the energy netting provision should remain in effect until termination of the cogeneration project or June 30, 1999, whichever occurs first. To provide consistent treatment for both schedules the adopted changes will become effective on June 30, 1989.

Special Contracts

The movement toward an increasingly competitive environment in the electric utility industry has generated concern over the loss of utility market share. We have addressed this concern by adopting marginal cost principles for revenue allocation and rate design. This is intended to prevent a bias for either utility or alternate energy sources. Although we have implemented marginal cost principles, our goal of marginal cost-based rates has been hampered by: (1) differences between marginal cost revenues and the utility's revenue requirement and (2) the magnitude of customer bill impacts. This has resulted in the approval of special contracts to avoid uneconomic bypass during a period of excess capacity. Rates for selected customers with special contracts have been as low as Standard Offer #1 price levels. D.88-03-008 states:

> "The term of a special contract conforming to the guidelines should not extend into any year when forecasts indicate that additional

> capacity will be needed to meet target reserve margins. The purpose of allowing special contracts is to take advantage of existing excess capacity. Considerable justification will be required to demonstrate the benefits of extending discounted rates into a period when increased demand creates a need for additional capacity." (P.16, D.88-03-008)

Exhibit 11, SDG&E's Report on Electric Resource Plan, December, 1987, indicates there is a clear need for new capacity beginning in 1989. This need for capacity has led IPC to recommend that: (1) SDG&E not offer rate discounts or discourage self-generation facilities and (2) the adopted rate schedules should not create economically unjustified barriers to self-generation.

We agree with IPC's position and believe our adopted rate schedules will not prevent the installation of economically justified self-generation facilities. We also share IPC's concern for special contracts and reemphasize our discussion in D.88-03-008 by the following:

> SDG&E should not enter into special contracts which provide customers with reduced rates in a year when forecasts indicate a need for additional capacity without substantial justification demonstrating the benefits for all other SDG&E ratepayers.

<u>Agricultural</u>

DRA and SDG&E were the only parties that made agricultural rate proposals. DRA endorses SDG&E's agricultrual rate structure proposal as discussed below:

1. Maintaining the present customer charges of \$8.00/month with an additional \$10.00/month for TOU meters on PA-TOU schedules.

2. Maintain the 3.401:1 relationship between on- and off-peak energy rates on the PA-TOU schedule.

3. Offer schedule PA-T-1 with a $20.00/month customer charge and preserve the existing relationship between agricultural and industrial TOU demand and energy charges.

4. Eliminate the current minimum charges for agricultural schedules.

No party opposed SDG&E's recommended agricultural rate structure and the Association of California Water Agencies by letter to the ALJ supported SDG&E's proposal. We will adopt SDG&E's recommended agricultural rate proposal.

Additionally, PA-TOU is an experimental TOU rate schedule similar to PA-T-1. However, PA-TOU is available to all agricultural customers, without the applicability restrictions of schedule PA-T-1. Since the Legislature has directed that TOU rate options be made available to agricultural customers and PA-TOU is the only rate schedule designed for all agricultural customers, it is appropriate to make this schedule a permanent option in addition to PA-T-1.

<u>Late Payment Charge</u>

SDG&E proposes to institute a late payment charge of 1.5% on all non-residential bills not paid within 25 days of the billing date. The City of San Diego recommends that the interest rate for the late payment charge be limited to SDG&E's balancing account rate. General Services objects to imposition of a late penalty charge against governmental facilities, the level of the charge, and the time allowed for payment of the charge. According to General Services, Government Code Section 926.17(b)(1) limits the amount of interest governmental facilities can be charged to 1% above the Pooled Money Investment Account, but not to exceed 15%. Additionally, General Services suggests that the time allowed for payment of the bill without penalty should be 50 days from the postmark date of mailing.

We will authorize SDG&E to establish a late payment charge for non-residential customers. The charge will only apply to balances that have not been paid within 25 days from the billing date. The monthly late payment charge should be calculated by applying SDG&E's authorized annual return on rate base rounded to the nearest one percent. In no event should governmental facilities be charged a late payment fee that exceeds the amount authorized by the Government Code.

SDG&E should not implement the late payment fee until March 1, 1989. This should provide adequate time for SDG&E to notify customers of the new charge and allow them to adjust their payment procedures, if warranted.

Street Lighting

SDG&E, DRA, California City-County Street Light Association (CAL-SLA), and the City of San Diego actively participated in this part of the proceeding. Street lighting rates are developed in two steps. Revenues are first allocated to the street lighting class. The class revenues are then used to determine individual rate schedules. The issues concerning this process are discussed below.

Revenue Allocation

All parties except SDG&E recommend a full EPMC revenue allocation, excluding facilities charges. Facilities charges are costs associated with end-use equipment, lamp poles, luminaires, etc. Facilities charges are typically removed from marginal cost revenue allocation methodologies because utilities do not provide end-use equipment to all classes.

SDG&E proposes that SAPC be used to allocate revenues to the street lighting class. SDG&E based its proposal on the following:

1. SAPC was used in its 1987 ECAC decision, D.87-12-069.

2. D.85-12-108, SDG&E's last general rate case decision, stated that the street lighting class should not experience a rate increase if the class revenues are in excess of marginal costs.

3. Current methodologies for determining street lighting marginal costs are not reliable.

Although DRA and CAL-SLA recommend the use of full EPMC, excluding facilities charges, CAL-SLA believes that DRA's marginal demand costs are too high. Since DRA and CAL-SLA propose similar revenues for marginal energy and customer costs, similar facilities charges, and similar EPMC multipliers, this represents their only difference for revenue allocation. The City of San Diego supports CAL-SLA's position.

CAL-SLA uses SDG&E's demand allocation factors which it believes accurately measure the demand street lights place on SDG&E's electric system. DRA uses coincident and non-coincident demands and estimates substation loadings as a function of total system demands to develop its allocation factors. This methodology assumes the maximum non-coincident demand billing determinants are equal to the sum of individual maximum demands for the class and determines coincident demands using LOLP-weightings which is consistent with DRA's methodology for other customer classes.

CAL-SLA argues that DRA's demand allocation process is inappropriate for street lighting because:

1. There is no need to estimate substation loadings since SDG&E presents loadings developed from load research.

2. There is no difference between maximum demand for the street lighting class and the sum of maximum demands for individual customers. All street lights come on and go off at the same time.

3. The load curve for the street lighting class is flat.

We will adopt DRA's revenue allocation methodology for street lighting, since it determines maximum demands from the sum of individual demands and is consistent with the revenue allocation methodology adopted for other customer classes.

Rate Design

SDG&E proposes that changes for individual street lighting rates be limited to plus or minus 5% from SAPC. In response to concerns for unbundled street lighting rates, SDG&E also developed an unbundled EPMC street lighting rate design. Additionally, SDG&E proposes a $6.00/pole/year attachment fee for LS-2 customers. SDG&E's pole attachment fee is based on an agreement it reached with the City of San Diego. Finally, SDG&E proposes that joint ownership of lighting facilities be eliminated and a service fee for de-energizing lights for non-payment be approved.

CAL-SLA states that there are inconsistencies in SDG&E's proposed EPMC rate design, which result in intra-class subsidization without economic justification. Accordingly, CAL-SLA recommends its unbundled rate design which focuses on the cost components that provide information on which service to purchase. CAL-SLA also objects to SDG&E's requested pole attachment fee arguing that:

1. Revenues are already collected to compensate for the space on distribution poles.
2. The proposed fee is not cost-based.
3. No estimate of pole attachment fee revenues was made.
4. Pole attachment fees were not reflected in miscellaneous revenues.
5. LS-2 customers would have to pay twice to amortize distribution poles.

DRA accepts the pole attachment fee negotiated by SDG&E and the City of San Diego and agrees with SDG&E's proposed elimination of jointly owned equipment.

Obviously, there is some benefit being derived from the use of SDG&E's poles for attaching street lights and cable television wires. If this benefit accrued to all SDG&E ratepayers there would be no need establish a pole attachment fee. Since all SDG&E ratepayers are not likely to be cable television subscribers, it is clear that all SDG&E ratepayers do not share in the benefits from attaching cable television wires to SDG&E's poles. Accordingly, we support the current policy of assessing pole attachment fees to cable television companies with the benefits passed on directly to all ratepayers.

In contrast to cable television wires, street lights generally benefit all SDG&E ratepayers. Street lights provide security and increased safety for the public by lighting streets, sidewalks, and other property. Because these benefits accrue to society as a whole and SDG&E ratepayers in particular, we conclude that there is no need for a pole attachment fee for street lights.

Finally, we will adopt CAL-SLA's EPMC unbundled rate design because it focuses on the cost components that provide information on which service to purchase.

Gas Rate Design

Gas marginal costs, cost allocation, and rate design are not addressed in this proceeding because the structure of gas rates was determined by D.86-12-010, D.86-12-009, and D.87-12-039. These decisions adopted a rate structure which is not subject to change for two years. Accordingly, SDG&E states that the only issues to be addressed are:

1. When SDG&E's authorized change in gas margin can be reflected in rates.
2. Baseline allowances.
3. Master meter unit discounts.

SDG&E points out that the agreement adopted by D.87-12-039 does not require all gas rate adjustments to be coincident with ACAP. Based on this interpretation, SDG&E requests that changes in its gas margin not be delayed until ACAP which has a scheduled effective date of July 1, 1989. DRA reads D.87-12-039 to limit rate changes to ACAP proceedings for two years.

Without a rate revision prior to ACAP, the margin change allocable to core customers would be placed in a balancing account, while the margin change allocable to non-core customers would not be recoverable. This discrepancy between customer groups is caused by the elimination of the supply adjustment balancing account for non-core customers. Margin recovery for non-core is now authorized prospectively.

To provide equitable treatment, we will authorize SDG&E to revise non-core rates, effective January 1, 1989. The revised non-core rates should reflect the change in margin adopted in this decision, but in all other respects the current revenue allocation and rate design methodology should remain unchanged. Since there is a balancing account for core customers, there is no compelling reason to reflect the increase authorized by this decision in rates at this time. We will adopt DRA's recommendation and not revise core customer rates until SDG&E's ACAP proceeding. Our adopted gas rates for non-core customers are shown in Appendix G.

This leads to a problem that exists with the level of detail contained in the Stipulation and Agreement adopted by D.88-09-063. To allocate costs between core and non-core customers specific detail for key cost data is required. D.88-09-063 combined with this decision set the level of costs to be used for revenue allocation in SDG&E's 1989 ACAP proceeding. Since the necessary level of detail for these costs is deficient, we will direct DRA and SDG&E to conduct workshops with the signatories to the Stipulation and Agreement. These workshops should identify the cost detail required for revenue allocation in SDG&E's 1989 ACAP proceeding. The results of these workshops should be served on all parties to this proceeding and SDG&E's last consolidated adjustment mechanism proceeding prior to SDG&E's ACAP filing.

Consistent with its recommendation for electric baseline allowances, DRA recommends that gas baseline allowances which conform with PU $ 739 continue to be phased-in. SDG&E argues that changes in baseline allowances will create an upward pressure on residential bills and, if changes are adopted, they should not be implemented until May 1, 1989, when seasonal baseline changes occur.

As with electric baseline allowances, we agree with DRA that continued phase-in of gas baseline allowances meets the requirements of PU $ 739 and will adopt its recommendation. Baseline allowances for gas customers will be reduced over a one to three year period starting May 1, 1989. The adopted baseline allowances are shown in Appendix G.

SDG&E, WMA, and DRA have agreed that the discount for mobilehome parks on schedule GT should be $6/unit/month or $0.197/unit/day. For apartment buildings on schedule GS, no party opposes SDG&E's proposed discount of $1.90/unit/month or $0.062/unit/day. These discounts appear reasonable and will be adopted.

Steam Rate Design

SDG&E provides steam service under two rate schedules which are closed to new customers. SDG&E's two steam schedules (1 and 2) differ only in that schedule 2 has one percent higher rates than schedule 1 to reflect an additional franchise fee requirement. Both consist of a service charge and a commodity charge per 1,000 pounds of steam provided.

SDG&E proposes that the service charge for each schedule be doubled to allow it to recover about 50% of its service costs. The schedule 1 customer charge would be $30.00/month and the schedule 2 customer charge would be $30.30/month. The commodity charge would recover the remaining revenue requirement. DRA agrees with SDG&E's proposal and notes that SDG&E's remaining steam customers have been notified of the proposed increases, but have made no response. We will adopt SDG&E's proposed rate changes for its steam schedules, as reflected in Appendix H.

Intervenor Funding

Pursuant to the Commission's Rules of Practice and Procedure Rule 76.54, Public Advocates, UCAN, CPIL, and Rate Watchers have filed requests for a finding of eligibility for compensation under Rule 76.56. Additionally, UCAN, CPIL, and Rate Watchers have filed requests for compensation. We will discuss each of these requests below.

Public Advocates

Public Advocates filed a request for finding of eligibility of attorneys' fees and other reasonable costs restricted to the issue of W/MBE contracts. Public Advocates states that it represents the following non-profit organizations on W/MBE issues: American G.I. Forum, League of United Latin American Citizens, and Filipino American Political Association. These organizations have annual budgets ranging from $25,000 to $50,000 with the majority of funds going to education. All officers of the organizations are volunteers and there are no salaries or legal expenses.

Additionally, Public Advocates indicates that individual members of the organizations are SDG&E ratepayers and it is impractical and economically infeasible for individual minority and female ratepayers to represent their interests adequately before the Commission. Moreover, none of the organizations involved has a financial benefit at stake. The benefit will go to those businesses and individuals who contract their services to utilities. Although the organizations may receive some benefit through the improved efficiency of SDG&E, this would be common to all ratepayers and certainly not significant compared to the cost of representing W/MBE interests. Public Advocates estimates that its cost of participation will be approximately $6,000.

Finally, Public advocates argues that it has: (1) diligently and efficiently pursued the issue affecting minority and women-owned businesses, (2) particular expertise in the field of W/MBE contracts, and (3) been involved with representing W/MBE rights in numerous ratemaking proceedings.

We conclude from Public Advocates' filing that: (1) it represents an interest necessary for a fair determination of the proceeding, which is not otherwise adequately represented, (2) the economic interest of the individual members of the organizations it represents is small in comparison to the cost of effective participation, and (3) it is eligible for compensation under Rule 76.54.

UCAN

UCAN states it was previously found eligible for compensation by D.88-03-023, which satisfies the requirement for financial hardship under Rule 76.54. Additionally, UCAN has provided an estimate of its cost of participation and a statement of the issues it addressed in the proceeding. Based on UCAN's filing and D.88-03-023 we conclude that UCAN is eligible for compensation.

UCAN has also requested intervenor compensation in the amount of $77,067. Of the requested amount, $25,000 is associated with the Stipulation and Agreement adopted by D.88-09-063 with the remainder for issues involving marginal cost, revenue allocation, rate design, and depreciation. The following is a summary of UCAN's request:

Stipulation and Agreement Issues

Attorney Fees & Expenses

Demand Side Management (42.3 hours) Procedural Issues (39.9 hours) Rate Base & Working Cash (24.85 hours) Settlement Conferences (23.1 hours)	
Total Attorney Fees @ $125/hour	$16,269
Air Travel ($927) Hotel & Meals ($244) Parking ($62) Copying, Telephone, Postage, & Misc. ($1,668)	
Total Expenses	$2,901
Total Attorney Fees & Expenses	$19,170

Expert Costs

Demand Side Management	$7,000
88 hours @ $50/hour Expert Assistance Review ($2,000) Secretarial Support 50 hours @ $12/hour	
Rate Base & Working Cash	$2,141
35.8 hours @ $55/hour 5 hours @ $35/hour	
Other Results of Operation Issues	$3,930
44.3 hours @ $55/hour 24.5 hours @ $45/hour 11.3 hours @ $35/hour	
Review of Operation & Maintenance	$900
6 hours @ $150/hour	
Copying, Telephone, Postage, & Misc.	$650
Total Expert Fees & Expenses	$14,621*
Total Fees & Expenses	$33,791*
Total Stipulation and Agreement Compensation Request	$25,000

* Corrected for Calculation Errors

Contested Matters

Attorney Fees & Expenses

Marginal Cost (72.2 hours)
Rate Design (82.25 hours)
Depreciation (20.25 hours)
Revenue Allocation (9.5 hours)
Resource Planning (5.0 hours)
Marginal Cost & Rate Design Unallocable (18.25 hours)
Preparation of Brief (68.3 hours)
Preparation of Compensation Request (13.7 hours)

Total Attorney Fees @ $125/hour	$36,181

Air Travel ($824)
Hotel & Meals ($167)
Parking ($44)
Copying, Telephone, Postage, & Misc. ($1,691)

Total Expenses	$2,726
Total Attorney Fees & Expenses	$38,907

Expert Costs

Marginal Costs
94 hours @ $55/hour
18.2 hours @ $45/hour
14.3 hours @ $35/hour
Rate Design
32.8 hours @ $55/hour
3.2 hours @ $45/hour
12.5 hours @ $35/hour
Revenue Allocation
39.6 hours @ $55/hour
1.7 hours @ $45/hour
1.5 hours @ $35/hour
Depreciation 9.5 hours @ $55/hour

Copying, Telephone, Postage, & Misc.	$1,055
Total Expert Fees & Expenses	$13,159
Total Contested Matters Compensation Request	$52,067

UCAN requests compensation for its work in demand-side management, rate base, working cash, settlement conferences, and procedural matters. Although these issues are part of the Stipulation and Agreement adopted by D.88-09-063, UCAN states that it made a substantial contribution to the decision.

For demand-side management UCAN points out that it submitted a 97 page report and that many of its recommendations were agreed to by DRA and SDG&E. UCAN also submitted a 127 page report on rate base and working cash and argues that its contribution to these issues, although not expressly acknowledged on the record, was substantial and compensable. Finally, UCAN was involved in a number public hearings, workshops, and settlement conferences for which it requests compensation and cites D.87-07-033 as precedent when the informality of a proceeding prevents precise assignment of contribution.

We agree with UCAN that it would be inappropriate to encourage intervenor participation in workshops and settlement conferences and deny compensation because there is no clear assignment of contribution. In this proceeding we are persuaded that UCAN was not only a signatory to the Stipulation and Agreement, but actively participated in the settlement process. We also recognize that UCAN has made a sincere effort by only requesting compensation for 74% of its total expenses related to the Stipulation and Agreement. Accordingly, we will award UCAN $25,000 for its contribution to the Stipulation and Agreement adopted in D.88-09-063.

As discussed in the marginal cost section of this decision UCAN made a number of recommendations that resulted in a substantial contribution to this decision, especially for directly assignable and customer accounting costs. In contrast, certain UCAN recommendations for directly assignable costs and its incremental/decremental methodology for marginal customer costs were not adopted. After weighting the issues on which UCAN prevailed versus those on which it did not, we conclude that UCAN should be compensated for 75% of its marginal cost request.

UCAN's opposition to SDG&E's proposals to impose late charges, telephone collection charges, and an increase in returned check charges on residential customers appears to have significantly influenced SDG&E's decision to drop the first two proposals. UCAN was the only party to actively oppose the returned check charge increase and clearly contributed to our denial of SDG&E's request. While UCAN participated in a number of other rate design issues, as detailed in the rate design discussion, its contribution did not substantially impact their final resolution. We conclude that UCAN should be awarded 33% of its request for its contribution to rate design issues.

For revenue allocation we predominantly adopted DRA's methodology. Since a considerable portion of UCAN's recommendations were either rejected or duplicated the work of other parties, we will only grant 10% of UCAN's requested compensation for this issue.

Finally, UCAN's recommendation concerning three life lengthening maintenance programs was adopted. This is discussed in the section on depreciation. Accordingly, UCAN will be provided 100% of its request for depreciation.

UCAN's total request for issues not related to the Stipulation and Agreement is $52,067. Based on the foregoing discussion we will award UCAN $28,118 for its contribution to this decision. Direct expenses and unallocable costs were prorated to conform with our discussion and UCAN's recommended allocation for briefing and petitioning costs: marginal cost 55%, revenue allocation 25%, rate design 10%, depreciation 5%, and other 5%. This is consistent with our treatment of out-of-pocket expenses in D.88-08-055. Since D.88-03-023 found UCAN's $125/hour rate for attorney fees reasonable, we have adopted it for this decision.

CPIL

On August 4, 1988 CPIL filed a request that it be found eligible for compensation and awarded $7,569. Additionally, CPIL moves that its request for a finding of eligibility be deemed timely filed under Rule 76.54(c).

Under Rule 76.54(a) a request for finding of eligibility for compensation must be filed within 30 days of the first prehearing conference, or within 45 days after the close of the evidentiary record. CPIL argues that its entry into this proceeding was for a limited purpose which occurred while the opening window was closed.

Although CPIL's participation began late in the proceeding, it was not precluded from filing a request for eligibility within 45 days after the close of the evidentiary record. Instead CPIL filed between the two windows. We realize that it is often difficult to precisely follow the rules governing intervenor compensation requests. It is not the intent of these rules to limit intervenor participation, but to provide an orderly process for requesting compensation. Since CPIL has made a reasonable effort to conform to these rules, its filing will be considered timely.

CPIL is a non-profit public interest group which represents the interest of customers who would have been subject to SDG&E's customer charge when service is temporarily disconnected. CPIL represents the interests of the unorganized and underrepresented in State regulatory proceedings, provides an academic center of learning in administrative law, and teaches direct clinic skills in public interest regulatory law. CPIL obtains financial support through grants, subscriptions to the California Regulatory Law Reporter, and legal advocate fees.

CPIL states that the customers that would have been impacted by SDG&E's proposed charge are not adequately represented by any other party and their individual economic interest is small.

SDG&E estimated that its proposed charge of $4.80/month for each month service is temporarily disconnected would generate $50,000 from 2000 customers. CPIL argues that this could hardly support intervention by individual customers and that CPIL's cost of $7,569 was cost-effective for the affected customers. Based on CPIL's representations we agree that it has met the requirements of Rule 76.54 and should be found eligible for compensation.

The following is a summary of CPIL's compensation request:

<u>Attorney Fees & Expenses</u>

	8.1 hours @ $200/hour	$1,620
	30.3 hours @ $125/hour	$3,781
	55.5 hours @ $30/hour	$1,665
	Postage	$503
Total Compensation Request		$7,569

CPIL's requested award is for the preparation of testimony, its compensation request, and participation during the proceeding. Through its testimony and participation CPIL claims to have made a substantial contribution to D.88-07-023. Although SDG&E withdrew its proposal to require residential customers to pay a reconnection charge for the period when service is disconnected, CPIL argues that SDG&E's withdrawal was in the face of CPIL's opposition. Additionally, CPIL states that D.88-07-023 confirmed CPIL's position opposing SDG&E's proposed charge.

SDG&E is opposed to CPIL's intervenor compensation request stating that CPIL did not make a significant contribution to D.88-07-023 and did not provide sufficient detail of its services and expenses.

A superficial look at D.88-07-023 might lead SDG&E to conclude that CPIL did not contribute to the decision. In D.88-07-023 we credit CPIL for its opposition to SDG&E's proposed charge, otherwise, the decision is silent with respect to SDG&E's

proposal. There are two reasons for this. First, SDG&E withdrew its proposal. Second, the elimination of the customer charge for all residential customers made SDG&E's proposal moot.

In this proceeding SDG&E presented a number of controversial proposals that were eventually withdrawn. While SDG&E should be commended for its willingness to rethink positions, this approach could cause intervenors to spend their limited resources without compensation. Fortunately, CPIL was the only party to aggressively oppose SDG&E's proposal. From this we conclude that withdrawal of the proposal was substantially influenced by CPIL's participation in the proceeding and that CPIL should be compensated for its effort.

Although CPIL should be awarded compensation, we are not satisfied with the description of services and expenditures it provided. Rule 76.56 requires that a claimant submit a detailed description of services and expenditures. A summary of total hours by individual does not meet this requirement. CPIL should have provided a precise description of the activities performed and the amount of time each person devoted to each activity.

Additionally, our review of UCAN's compensation request, which provides considerable detail, indicates CPIL's request is excessively high in relation to the complexity and the limited litigation of the issue. For example, both revenue allocation and depreciation issues were far more complex and extensively litigated, but UCAN's combined costs for these issues is less than $10,000. Accordingly, we will award CPIL 50% of its request as reasonable compensation.

Finally, we are not satisfied with CPIL's basis for charging $200/hour for Robert Fellmeth's legal work. CPIL's sole reason for increasing Robert Fellmeth's $150 hourly rate, adopted in D.87-05-030, was that his current rate is $200/hour. Without adequate justification for an increase, we will use $150/hour as Robert Fellmeth's hourly rate. This rate is consistent with the hourly rates we have adopted in recent intervenor compensation awards and CIPL's request for sanctions in I.88-08-046.

The above adjustments to CPIL's compensation request result in an award of $3,582.

Rate Watchers

Rate Watchers is a newly formed advocacy group of SDG&E ratepayers which on August 18, 1988 filed a request for a finding of eligibility for compensation and an award of $5,163. Rate Watchers states that it receives no grants, is supported only by the limited resources of its members and claims the economic interests of its individual members is small in comparison to the cost of participation.

As with CPIL, Rate Watchers filed it request for finding of eligibility more than 30 days after the first prehearing conference and prior to 45 days from the close of the evidentiary record. Consistent with our treatment of CPIL's request, we will consider Rate Watchers' eligibility request to be timely filed. However, in future proceedings we suggest that Rate Watchers file eligibility requests within 30 days of the first prehearing conference. This procedure would allow us to point out similar positions of other parties, areas of potential duplication, and unrealistic expectations for compensation.

The following is a summary of Rate Watchers compensation request:

<u>Expert Costs</u>

Parade Activities	$580
20 hours @ $22/hour	
2 hours @ $55/hour	
3 hours @ $10/hour	
Public Hearings Participation	$2,156
28 hours @ $22/hour	
28 hours @ $55/hour	
Preparation for Evidentiary Hearings	$121
3 hours @ $22/hour	
1 hour @ $55/hour	
Attend Evidentiary Hearings	$1,320
24 hours @ $55/hour	
Comments on Interim Order	$265
4 hours @ $45/hour	
1 hour @ $55/hour	
3 hours @ $10/hour	
Postage & Misc. Office Supplies	$75
Telephone	$135
Transportation	$61
Parking	$40
Printed Flyers	$210
Stickers & Signs	$106
Bullhorn Rental	$94
Total Compensation Request	$5,163

D.88-07-023 repealed the $4.80 customer charge for residential customers and reestablished the $5.00 minimum bill. Rate Watchers asserts that it substantially contributed to that decision through organizing a prehearing parade and demonstration, and other activities intended to increase the extent of opposition to the customer charge expressed at the public hearings. Rate Watchers also claims responsibility for providing witnesses and evidence from which D.88-07-023 concluded a climate of distrust and perceived unfairness contributed to the lack of customer understanding of the customer charge. While UCAN and CPIL and DRA represented the interest of residential ratepayers, only Rate

Watchers adequately represented the narrow issue of the customer charge impact on customers.

SDG&E opposes Rate Watchers request for compensation on the basis that Rate Watchers activities are not compensable.

Rate Watchers' participation in the public and evidentiary hearings clearly defined the scope of customer dissatisfaction with SDG&E's customer charge and contributed to its repeal in D.88-07-023. Although we conclude that Rate Watchers should be awarded compensation, a considerable amount or their request is not compensable. Rate Watchers will only be awarded compensation for its participation in the public and evidentiary hearings, and comments on the ALJ's proposed decision relating to the customer charge. Additionally, we will reduce the number of hours for public hearings by half to reflect the actual amount of hearing time. We will not award compensation for parade activities, printed flyers, stickers, signs, and bullhorn rental.

Finally, we believe the level of regulatory expertise exhibited by Rate Watchers to be comparable to that of CPIL's law clerks and paralegals. Accordingly we will limit Rate Watchers' hourly rate to that charged by CPIL for similar regulatory expertise, $30/hour.

The above adjustments result in a total compensation award for Rate Watchers of $2,038.

<u>Findings of Fact</u>

1. On December 1, 1987 SDG&E filed A.87-12-003 requesting authority to reduce rates for its electric department and increase rates for its gas and steam departments for test year 1989.

2. SDG&E's A.87-12-003 requests attrition increases in 1990 and 1991.

3. Two days of public participation hearings were held in March, 1988 and 21 days of evidentiary hearings were held between April and September, 1988.

4. Except for depreciation and cost of capital, revenue requirements items normally litigated in SDG&E's general rate proceeding were agreed to in a Stipulation and Agreement and adopted in D.88-09-063.

5. Cost of capital issues were bifurcated and consolidated with other energy utilities in a generic cost of capital proceeding.

6. D.88-09-063 provided for revisions to the adopted Stipulation and Agreement for NRC fees, labor and non-labor escalation rates, EPRI dues, and W/MBE program costs.

7. SDG&E submitted a reliability of service study in compliance with D.87-12-069.

8. SDG&E, PG&E, and Edison expect to submit a comparison of rates study by June 1, 1989.

9. SDG&E estimates that as of December 31, 1988 CLMAC will have overcollected electric revenues by $10.5 million and gas revenues by $4.0 million.

10. DRA's Standard Practice U-4 has consistently been adopted for ratemaking depreciation.

11. U-4 provides a formalization of the theory of depreciation and guidelines for performing the statistical analyses on which depreciation computations are based.

12. U-4's remaining life methodology recovers the original cost of depreciable fixed capital less net salvage value over the useful life of the asset.

13. SDG&E proposes that the remaining lives for 17 electric department plant accounts be adjusted by using a method referred to as QAU.

14. SDG&E has included in its requested level of O&M expense three programs, wood pole treatment, underground switch maintenance, and padmount transformer painting, that are expected to extend the lives of various plant and equipment.

15. SDG&E's QAU methodology only considers life shortening uncertainties.

16. SDG&E has not provided the support for the assumptions developed from its QAU interviews.

17. U-4 methodology can increase or decrease the average remaining lives of plant accounts to reflect past and expected retirements.

18. Depreciation analysts use judgment in the development of average remaining plant lives.

19. Mortality and other historic data are the primary inputs used for the development of average remaining lives.

20. U-4 does not limit depreciation analysts to the use of historical data, information on product life from manufacturers or known changes in plant can also be used to develop average remaining lives.

21. FCC represcribes depreciation rates at three-year intervals for telecommunication utilities.

22. Under FCC's represcription procedure a telecommunication utility submits proposed changes in depreciation to DRA and FCC staff, DRA and FCC staff develop recommendations, and areas of disagreement are discussed in a joint meeting with all three.

23. Depreciation rates for energy utilities are determined on a three-year cycle in general rate proceedings.

24. D.84-06-111 adopted technical updates for Pacific Bell that provide for automatic adjustment of depreciation rates to account for changes in the composition of utility plant and relative growth or decline in depreciation reserve.

25. G.O. 156 requires SDG&E to participate in a clearinghouse for verification of W/MBEs.

26. The Stipulation and Agreement adopted in D.88-09-063 provides for increased W/MBE funding up to $200,000 for additional W/MBE activities such as a clearinghouse for W/MBEs.

27. G.O. 156 establishes goals for SDG&E's W/MBE program and verification of W/MBEs.

28. D.87-12-066 ordered Edison to encourage W/MBE joint ventures and provide technical assistance in meeting financing and insurance requirements at competitive rates.

29. SDG&E and DRA agree on the principles to be used in preparing SDG&E's 1990 and 1991 attrition filings.

30. SDG&E's current attrition mechanism adjusts estimated plant additions for changes in escalation factors.

31. DRA excludes non-recurring and hazardous waste projects from the four-year average of plant additions used to estimate plant additions for attrition.

32. The integrated voice and data network project excluded from DRA's average of plant additions for attrition is expected to reoccur in attrition years 1990 and 1991.

33. PG&E's and Edison's adopted attrition methodology does not adjust estimated plant additions for changes in escalation rates.

34. Edison's budget for 1990 nuclear plant additions has been subject to review by DRA.

35. SDG&E's nuclear O&M expenses for 1989 and 1990 were adopted in D.87-12-066, Edison's 1988 general rate case decision.

36. All parties agreed to use DRA's marginal energy cost estimates.

37. There is no disagreement with the use of DRA's marginal demand cost methodology.

38. SDG&E agreed to the following UCAN recommendations: (1) no contingency factor for TSM costs, (2) 4% for purchasing and warehousing transformer costs, and (3) a weighted average of single-family and multi-family units for customers on schedule DR.

39. DRA's weighting of single-family and multi-family units is based on test period housing stock.

40. UCAN's weighting of single-family and multi-family units is based on the weighting of incremental customers.

41. SDG&E did not provide an explanation for the difference between its labor overhead rate of 129% for meter installations and its 111% labor overhead rate used on work orders for customer costs.

42. SDG&E's estimate of transformer costs was developed from a moving average inventory price.

43. UCAN's estimate of transformer costs was based on the incremental cost of SDG&E's transformer purchase contracts.

44. To annualize TSM investments, UCAN excluded three FERC accounts that it felt were not related to TSM investments from SDG&E's real fixed rate.

45. DRA's real fixed rate for annualizing TSM costs was calculated using the same method as UCAN, but only two FERC accounts were excluded. The third account, which relates to protective devices and capacitors, DRA believes is associated with TSM investments.

46. SDG&E's common distribution cost methodology uses a proxy for the minimum distribution system to represent common distribution costs which are dedicated to the service of customers as distinguished from meeting their demands.

47. DRA's common distribution cost methodology identifies specific equipment as access related and assigns the investment costs directly to the appropriate customer class.

48. SDG&E has corrected its customer accounting costs for inconsistencies between its marginal cost calculation and its results of operation calculation.

49. SDG&E did not reflect differences in the cost of reading meters in its customer accounting costs.

50. SDG&E included conservation expenses in its customer accounting costs.

51. UCAN's incremental/decremental methodology reflects a hookup charge for new customers and decremental costs for existing customers.

52. UCAN's incremental/decremental methodology assumes that competitive providers of access equipment would be able to undercut SDG&E's investment costs by 75%.

53. DRA's market rental approach for marginal customer costs assumes that customers rent access equipment. Where customer ownership of access equipment exists customers are excluded from the allocation process.

54. SDG&E agreed to DRA's marginal energy revenues prior to revision for a revenue-related tax factor which was inadvertently omitted.

55. DRA calculated generation demand for test year 1989 at 1992 MW using LOLP-weighted demands.

56. Recorded 1986 generation demand was 2376 MW.

57. SDG&E, UCAN, and FEA used DRA's methodology for the calculation of distribution demand.

58. DRA assumed that on average 20 customers are connected to each residential transformer and that no more than 25% of the maximum load of all individual customers connected to any residential transformer will occur at the same time.

59. SDG&E's distribution planning manual instructs planning engineers to use a diversity factor between 55% and 75% when 10 customers are connected to one transformer.

60. SDG&E did not provide supporting data for the average number of residential customers connected to each transformer, but argues that less than 10 are likely to be connected to a new transformer.

61. Full EPMC revenue allocation is consistent with our general policy of marginal cost-based rates.

62. Most customer classes under full EPMC revenue allocation receive decreases within plus or minus 4% of SAPC, with the largest decrease to the agricultural class, 18%, and the smallest to the residential class, 6%.

63. D.88-07-023 replaced the $4.80/month residential customer charge with a $5.00/month minimum bill.

64. D.88-10-062 addresses the realignment of baseline and nonbaseline rates in compliance with SB 987.

65. D.85-12-108 in SDG&E's last general rate proceeding adopted a phase-in of baseline allowances.

66. Some SDG&E gas and electric baseline allowances are not in conformance with PU § 739.

67. SDG&E failed to provide convincing testimony that it is unable to negotiate lower bank fees for returned checks.

68. SDG&E, WMA, and DRA agree that the mobilehome park discount should be $9.50/unit/month on schedule DT and $6.00/unit/month on schedule GT, to be prorated and billed on a daily basis.

69. SDG&E and DRA agree that the discount for apartment buildings should be $4.04/unit/month on schedule DS and $1.90 on schedule GS, to be prorated and billed on a daily basis.

70. SDG&E, DRA, and UCAN agree on the design of residential TOU schedules.

71. SDG&E withdrew the following residential rate design proposals: (1) late payment charge, (2) telephone charge with respect to bill collections, (3) customer charge, and (4) reconnection charge for the period when service is disconnected.

72. SDG&E proposes a two tiered declining block energy rate for schedule AD.

73. The schedule AD demand charge is below SDG&E's marginal capacity cost.

74. SDG&E's witness testified that it was reasonable to provide a TOU option to schedule A and AD customers.

75. D.87-12-069 in SDG&E's 1987 ECAC proceeding adopted major changes for schedules AL-TOU and A6-TOU. These changes provide for higher demand charges and lower energy rates.

76. Marginal capacity costs in this proceeding are less than those used to design the AL-TOU and A6-TOU schedules adopted in D.87-12-069.

77. SDG&E and DRA have addressed Poway's concerns for the start of the on-peak period for TOU schedules in A.88-07-003.

78. Schedules AO-TOU and A06-TOU are optional rate schedules which were closed to new customers as of July 1, 1988. No party opposed SDG&E's recommendation to maintain demand charges at their existing level and decrease all energy charges by an equal percent.

79. Interruptible service schedules do not reflect the changes in the AL-TOU demand structure adopted in D.87-12-069.

80. Coincident demand charges on schedule AL-TOU may contain more than coincident capacity costs.

81. Schedules AE-1, R-TOU-1, and R-TOU-2 are experimental real time pricing schedules which are optional for AL-TOU and A6-TOU customers, terminate on January 1, 1992, and provide for a 12-month termination notice.

82. SDG&E's AE-1, R-TOU-1 and R-TOU-2 schedules do not reflect the changes to schedules AL-TOU and A6-TOU adopted in D.87-12-069.

83. SDG&E's electric rule 2(G) authorizes a charge for power factors below 90% of their kilowatt demand. SDG&E's present rate authorizes it to charge $0.21/kVAR/month when a customer's power factor is below 75%.

84. Customers which have low power factors cause SDG&E to install capacitors to maintain system capacity.

85. Standby customers which take service under more than one rate schedule could bypass certain rates by taking service under one schedule during on-peak periods and a different schedule during off-peak periods.

86. SDG&E has not provided adequate justification for requiring a Commission-approved contract before customers with contract capacity exceeding 20 MW can receive standby service.

87. SDG&E's current standby rate structure was designed to be consistent with our standby policy adopted in D.86-12-091.

88. No party has demonstrated a need to change the standby policy adopted in D.86-12-091.

89. SDG&E's standby rate schedule requires customers to pay a non-coincident demand charge based on 80% of their contract load.

90. Schedule AD customers pay a combined coincident and non-coincident demand charge.

91. PG is an experimental schedule for customers with generation facilities. This schedule has no standby charge and customers are allowed to credit excess electricity produced against consumption during other periods.

92. Schedule PG does not recover SDG&E's full cost of service because of the lack of standby charges and the energy netting provision.

93. D.87-12-069 closed schedule PG-QF to new cogeneration facilities above 20 kW by June 30, 1989.

94. DRA and the Association of California Water Agencies support SDG&E's agricultural proposal as described in the rate design section of this decision.

95. Costs associated with late payments by non-residential customers are paid by all customers.

96. SDG&E's Report on Electric Resource Plan, December, 1987, indicates there is a clear need for new capacity beginning in 1989.

97. DRA and SDG&E submitted a joint exhibit (Exhibit 43) that sets forth guidelines on the manner in which SDG&E will conduct its next standard offer proceeding.

98. Exhibit 43 set forth criteria and considerations for SDG&E to include in undertaking its periodic resource planning activities.

99. DRA's full EPMC revenue allocation methodology for the street lighting class determines maximum demands from the sum of individual demands and is consistent with the revenue allocation methodology used for other customer classes.

100. CAL-SLA's EPMC unbundled street light rate design focuses on the cost components that provide information on which services to purchase.

101. Gas marginal costs, cost allocation, and rate design are not addressed in this proceeding because the structure of gas rates was determined by D.86-12-010, D.86-12-009, and D.87-12-039. These decisions adopted a rate structure that is not subject to change for two years.

102. Margin rate changes for core gas customers are subject to balancing account treatment.

103. Margin recovery for non-core gas customers is authorized prospectively and not subject to balancing account treatment.

104. Adequate detail of the costs necessary for revenue allocation in SDG&E's 1989 ACAP was not provided in the Stipulation and Agreement adopted in D.88-09-063.

105. DRA supports SDG&E's steam rate design proposal.

106. Public Advocates, UCAN, CPIL, and Rate Watchers request a finding of eligibility for compensation pursuant to Rule 76.54.

107. Public Advocates, UCAN, CPIL, and Rate Watchers each: (1) participated in one or more issues that was otherwise not adequately represented, (2) represented organizations or SDG&E ratepayers which have an economic interest that is small in comparison to the cost of effective participation, and (3) would experience financial hardship for their cost of participation without an award.

108. UCAN is a signatory to the Stipulation and Agreement adopted in D.88-09-063 and only requests compensation for 74% of its total expenses related to the Stipulation and Agreement.

109. UCAN made a number of recommendations that resulted in a substantial contribution to the marginal cost section of this decision.

110. UCAN minimumly contributed to the adopted revenue allocation methodology, but UCAN's recommendation concerning three life lengthening maintenance programs for depreciation expense was adopted in its entirety.

111. Some of UCAN's rate design proposals contributed to this decision.

112. CPIL substantially influenced SDG&E's withdrawal of the proposal to require residential customers to pay a reconnection charge for the period when service is disconnected.

113. CPIL did not submit a detailed description of services and expenditures and did not adequately justify increasing Robert Fellmeth's hourly rate for legal work from $150 to $200.

114. UCAN's combined compensation request for revenue allocation and depreciation, which were each more complex than the issue CPIL addressed, was less than $10,000 as compared to CPIL's request of $7,569.

115. Rate Watchers' participation in the public and evidentiary hearings clearly defined the scope of customer dissatisfaction with SDG&E's customer charge and contributed to its appeal.

116. A considerable amount of Rate Watchers' request is not compensable.

117. The level of regulatory expertise exhibited by Rate Watchers is comparable to that of CPIL's law clerks and paralegals.

<u>Conclusions of Law</u>

1. D.88-09-063 should be revised to reflect changes in NRC fees, labor and non-labor escalation rates, EPRI dues, and W/MBE program costs.

2. Consistent with its rate case cycle SDG&E's estimate of CLMAC overcollections should be amortized over three years.

3. In its 1990 attrition year filing SDG&E should amortize any difference between the estimated and actual CLMAC balance over two years.

4. SDG&E's QAU methodology expands the depreciation analysts's use of judgment.

5. Depreciation analysts should clearly identify all information that adjusts average remaining plant lives and the source of the information.

6. Depreciation analysts should detail the weight given to each event and how it impacts the calculation of average remaining plant lives.

7. SDG&E's QAU methodology was only designed to receive input which would shorten life expectancies and as a result is inherently biased.

8. SDG&E's depreciation methodology requires the independent application of judgment twice.

9. SDG&E's QAU model is based on speculative assumptions and not recorded data.

10. The depreciation analyst should consider all events which could affect plant lives at the same time and adjust average service lives accordingly.

11. A reasonable approach to determine average service plant lives should solicit information from experts, provide their identity, describe their input, and indicate how the information was applied.

12. A procedure similar to represcription is reasonable and should be adopted for SDG&E.

13. Depreciation workshops as previously described should be adopted for SDG&E's future general rate proceedings.

14. DRA's recommended depreciation expense and accruals, which exclude QAU, should be adopted.

15. SDG&E and DRA should address the issue of technical depreciation updates in SDG&E's next general rate proceeding.

16. SDG&E's life extending programs, pole butt treatment, underground switch maintenance, and padmount painting should be considered in determining the average remaining lives for the affected plant.

17. SDG&E should be provided an additional $200,000 in W/MBE funding for its participation in the clearinghouse for verifying W/MBEs.

18. SDG&E should encourage W/MBE joint ventures and provide technical assistance in meeting financing and insurance requirements at competitive rates.

19. SDG&E's attrition mechanism should use a four-year average excluding non-recurring and hazardous waste projects to estimate plant additions.

20. The integrated voice and data network project is expected to reoccur in attrition years 1990 and 1991 and should be included in the four-year average of plant additions.

21. SDG&E's estimated plant additions for attrition years should not be adjusted for changes in escalation rates.

22. Edison's budget for 1990 nuclear plant additions should be adopted for use in SDG&E's attrition year 1990 filing.

23. The nuclear O&M expenses and plant estimates adopted in Edison's 1991 test year general rate proceeding should be used for SDG&E's attrition year 1991 filing.

24. DRA's marginal energy costs revised to reflect the appropriate revenue-related tax factor, and marginal demand costs as shown in Appendix E should be adopted.

25. For directly assignable costs the following UCAN recommendations should be adopted: (1) no contingency factor for residential or small commercial TSM costs, (2) 4% for purchasing and warehousing transformer costs, (3) a weighted average of single-family and multi-family units for customers on schedule DR, (4) an overhead rate of 111%, and (5) transformer costs based on SDG&E's incremental cost.

26. DRA's weighting of single-family and multi-family units and 10% real fixed rate for annualizing TSM costs should be adopted for determining directly assignable costs.

27. DRA's common distribution cost methodology should be adopted.

28. UCAN's recommendations that customer accounting costs reflect the differences in the cost of reading meters and exclude conservation expenses should be adopted.

29. DRA's market rental approach should be adopted for determining marginal customer costs.

30. DRA's revised marginal energy revenue determinants should be adopted.

31. Except for its reliability adjustment and diversity factor for residential class transmission and distribution demands, DRA's methodology, weighting factors, and demand determinants for calculating marginal cost revenues should be adopted.

32. A system peak of 2376 MW should be used for 1989 generation demand.

33. DRA's distribution and transmission demand adjusted for a 50% diversity factor for the residential class should be adopted.

34. The Full EPMC revenue allocation shown in Appendix D should be adopted.

35. The phased-in electric and gas baseline allowances shown in Appendices F and G are in conformance with PU $ 739 and should be adopted.

36. A mobilehome park discount of of $9.50/unit/month for schedule DT and $6.00/unit/month, both to be prorated and billed on a daily basis, for schedule GT should be adopted.

37. A discount for apartment buildings of $4.04/unit/month for schedule DS and $1.90/unit/month, both to be prorated and billed on a daily basis, for schedule GS should be adopted.

38. Declining block energy rates encourage energy use and are not consistent with our conservation policies.

39. DRA's recommended $5.50/kW demand charge for schedule AD should be adopted.

40. Schedule A and AD customers should be allowed to move to a TOU schedule.

41. Maintaining the existing off-, mid-, and on-peak energy relationships should provide customers on schedules AL-TOU and A6-TOU with a better understanding of the adopted rates.

42. The off- and mid-peak energy rates for SDG&E's experimental schedules AE-1, R-TOU-1, and R-TOU-2 should be adjusted to reflect the adopted revenue requirement, but the schedules should be closed to new customers.

43. Three new real time pricing schedules which incorporate the rate structure changes to schedules AL-TOU and A6-TOU, should be adopted.

44. DRA's recommended interruptible service schedules should be adopted.

45. Customers with power factors below 90% should be assessed SDG&E's current charge of $0.21/kVAR month.

46. Customers should be provided six months to correct their power factors before being assessed a kVAR charge.

47. Revenues from power factor charges should be treated in the same manner as standby revenues.

48. The proposals to change SDG&E's current standby rate structure are not consistent with the standby policy adopted in D.86-12-091.

49. SDG&E should provide in its next general rate case filing sufficient data to permit the determination of facilities dedicated to standby service including transmission and distribution facilities that are not fully diversified.

50. Schedule AD customers should be allowed to take standby service and receive credit for the non-coincident demand charges on their contracted standby load.

51. The energy netting provision of schedule PG should be closed to all customers and the schedule should be closed to new customers on June 30, 1989.

52. Consistent with D.87-12-069 schedule PG-QF should be closed to new cogeneration facilities above 20 kW by June 30, 1989. For customers on PG-QF prior to June 30, 1989 the energy netting provision should remain in effect until termination of the cogeneration project or June 30, 1999, whichever occurs first.

53. SDG&E's agricultural rate design as shown in Appendix F should be adopted.

54. On or after March 1, 1989 SDG&E should be authorized to establish a late payment charge for non-residential customers. The charge should only apply to balances that have not been paid within 25 days from the billing date and be calculated by applying SDG&E's authorized annual return on rate base rounded to the nearest one percent. Governmental facilities should not be charged a late payment fee that exceeds the amount authorized by the Government Code.

55. SDG&E should not enter special contracts which provide customers with reduced rates in a year when forecasts indicate the need for additional capacity without substantial justification demonstrating the benefits for all SDG&E ratepayers.

56. Exhibit 43 on the resource plan submitted by DRA and SDG&E establishes guidelines and criteria for resource planning that are reasonable and should be implemented.

57. DRA's EPMC revenue allocation for the street lighting class should be adopted.

58. CAL-SLA's EPMC unbundled street lighting rate design should be adopted because it focuses on the cost components that provide information on which service to purchase.

59. SDG&E should be authorized to revise non-core gas rates, effective January 1, 1989, to reflect the change in margin adopted in this decision. The current revenue allocation and rate design

methodology should remain unchanged. The margin change allocable to the core gas customers of $9.644 million as shown in Appendix G, should be reflected in the core balancing account to be addressed in SDG&E's ACAP.

60. The non-core gas rates in Appendix G should be adopted.

61. SDG&E should be authorized to increase its electric, gas, and steam margins to reflect the revenue requirement shown in Appendix A.

62. DRA and SDG&E should conduct workshops with the signatories to the Stipulation and Agreement to identify the cost detail required for revenue allocation in SDG&E's 1989 ACAP. The results of these workshops should be served on all parties to this proceeding and SDG&E's last gas offset proceeding prior to SDG&E's 1989 ACAP filing.

63. SDG&E's proposed steam rate design as shown in Appendix H should be adopted.

64. Public Advocates, UCAN, CPIL, and Rate Watchers should be found eligible for compensation under Rule 76.54

65. CPIL should be awarded $3,582 in compensation for its contribution to D.88-07-023.

66. Rate Watchers should be awarded $2,038 in compensation for its contribution to D.88-07-023.

67. Interest should be paid on CPIL's and Rate Watchers' award from the 76th day after their request was filed until the payment of the award is made. The interest should be calculated in the same manner as the deferred account established in D.86-06-079.

68. UCAN should be awarded $53,118 for its contribution to D.88-09-063 and this decision.

69. Effective January 1, 1989 SDG&E should be directed to decrease its electric rates by $94.9 million or 7.6% and authorized to increase its gas rates for non-core customers by $1.5 million or 0.7% and steam rates by $0.6 million or 51.3%.

8. SDG&E shall encourage joint ventures with women- and minority-owned business and shall provide technical assistance in meeting financing and insurance requirements at competitive rates.

9. For its attrition year 1991 filing SDG&E is authorized to use the nuclear O&M expenses and plant estimates adopted in Southern California Edison Company's 1991 test year general rate proceeding.

10. DRA and SDG&E shall conduct workshops with the signatories to the Stipulation and Agreement to identify the cost detail required for revenue allocation in SDG&E's 1989 ACAP. The results of these workshops shall be served on all parties to this proceeding and SDG&E's last gas offset proceeding prior to SDG&E's 1989 ACAP filing.

11. The guidelines and criteria for the resource planning activities set forth in Exhibit 43 shall be implemented in the next SDG&E standard offer proceeding and in carrying out SDG&E's resource planning activities.

12. Experimental schedules AE-1, R-TOU-1, and R-TOU-2 shall be closed to new customers on the effective date of this decision.

13. On June 30, 1989 schedule PG shall be closed to new customers and the schedule's energy netting provision shall be closed to all customers.

14. On June 30, 1989 schedule PG-QF shall be closed to new cogeneration facilities above 20 kW. The energy netting provision PG-QF shall remain in effect for existing customers, on the schedule prior to June 30, 1989, until termination of the cogeneration project or June 30, 1999, whichever occurs first.

15. In its next general rate case filing SDG&E shall provide sufficient data to permit the determination of facilities dedicated to standby service including transmission and distribution facilities that are not fully diversified.

CORRECTION

THIS DOCUMENT HAS

BEEN REPHOTOGRAPHED

TO ASSURE

LEGIBILITY

methodology should remain unchanged. The margin change allocable to the core gas customers of $9.644 million as shown in Appendix G, should be reflected in the core balancing account to be addressed in SDG&E's ACAP.

60. The non-core gas rates in Appendix G should be adopted.

61. SDG&E should be authorized to increase its electric, gas, and steam margins to reflect the revenue requirement shown in Appendix A.

62. DRA and SDG&E should conduct workshops with the signatories to the Stipulation and Agreement to identify the cost detail required for revenue allocation in SDG&E's 1989 ACAP. The results of these workshops should be served on all parties to this proceeding and SDG&E's last gas offset proceeding prior to SDG&E's 1989 ACAP filing.

63. SDG&E's proposed steam rate design as shown in Appendix H should be adopted.

64. Public Advocates, UCAN, CPIL, and Rate Watchers should be found eligible for compensation under Rule 76.54

65. CPIL should be awarded $3,582 in compensation for its contribution to D.88-07-023.

66. Rate Watchers should be awarded $2,038 in compensation for its contribution to D.88-07-023.

67. Interest should be paid on CPIL's and Rate Watchers' award from the 76th day after their request was filed until the payment of the award is made. The interest should be calculated in the same manner as the deferred account established in D.86-06-079.

68. UCAN should be awarded $53,118 for its contribution to D.88-09-063 and this decision.

69. Effective January 1, 1989 SDG&E should be directed to decrease its electric rates by $94.9 million or 7.6% and authorized to increase its gas rates for non-core customers by $1.5 million or 0.7% and steam rates by $0.6 million or 51.3%.

70. The electric, gas, and steam rates shown in Appendices E, F, and G are reasonable and should be adopted.

71. The decreases and increases in rates and charges authorized by this decision are justified, and are just and reasonable.

INTERIM ORDER

IT IS ORDERED that:

1. San Diego Gas & Electric Company (SDG&E) is authorized and directed to file with this Commission, on or after the effective date of this order, and not later than December 28, 1988, revised tariff schedules for electric, gas, and steam rates as set forth in Appendices F, G, and H.

2. The revised tariff schedules shall become effective on or after January 1, 1989 and shall comply with General Order 96-A. The revised tariffs shall apply to service rendered on or after their effective date.

3. SDG&E is authorized to increase its electric, gas, and steam margins to reflect the adopted revenue requirement shown in Appendix A, and to reflect the split of core and non-core gas margin shown in Apendix G, page 2.

4. SDG&E is authorized to file attrition adjustments for the years 1990 and 1991 based on the methodology and revenue requirement set forth in Appendix B.

5. In its 1990 attrition year filing SDG&E shall amortize any difference between the estimated and actual CLMAC balance over two years.

6. SDG&E and the Division of Ratepayer Advocates (DRA) shall conduct depreciation workshops as discussed in this decision for SDG&E's future general rate proceedings.

7. SDG&E and DRA shall address the issue of technical depreciation updates in SDG&E's next general rate proceeding.

8. SDG&E shall encourage joint ventures with women- and minority-owned business and shall provide technical assistance in meeting financing and insurance requirements at competitive rates.

9. For its attrition year 1991 filing SDG&E is authorized to use the nuclear O&M expenses and plant estimates adopted in Southern California Edison Company's 1991 test year general rate proceeding.

10. DRA and SDG&E shall conduct workshops with the signatories to the Stipulation and Agreement to identify the cost detail required for revenue allocation in SDG&E's 1989 ACAP. The results of these workshops shall be served on all parties to this proceeding and SDG&E's last gas offset proceeding prior to SDG&E's 1989 ACAP filing.

11. The guidelines and criteria for the resource planning activities set forth in Exhibit 43 shall be implemented in the next SDG&E standard offer proceeding and in carrying out SDG&E's resource planning activities.

12. Experimental schedules AE-1, R-TOU-1, and R-TOU-2 shall be closed to new customers on the effective date of this decision.

13. On June 30, 1989 schedule PG shall be closed to new customers and the schedule's energy netting provision shall be closed to all customers.

14. On June 30, 1989 schedule PG-QF shall be closed to new cogeneration facilities above 20 kW. The energy netting provision PG-QF shall remain in effect for existing customers, on the schedule prior to June 30, 1989, until termination of the cogeneration project or June 30, 1999, whichever occurs first.

15. In its next general rate case filing SDG&E shall provide sufficient data to permit the determination of facilities dedicated to standby service including transmission and distribution facilities that are not fully diversified.

16. On or after March 1, 1989, SDG&E is authorized to establish a late payment charge for non-residential customers. The charge shall only apply to balances that have not been paid within 25 days from the billing date and be calculated by applying SDG&E's authorized annual return on rate base rounded to the nearest one percent. Governmental facilities shall not be charged a late payment fee that exceeds the amount authorized by the Government Code.

17. SDG&E shall pay Center for Public Interest Law (CPIL) $3,582 and Rate Watchers $2,038 within 15 days from today in compensation for their contribution to D.88-07-023.

18. Interest shall be paid on CPIL's and Rate Watchers' award from the 76th day after their request was filed until the payment of the award is made and shall be calculated in the same manner as the deferred account established in D.86-06-079.

19. SDG&E shall pay Utility Consumers Action Network (UCAN) $53,118 within 15 days from today in compensation for its contribution to D.88-09-063 and this decision.

20. Public Advocates is eligible to request intervenor compensation for its contribution to this decision.

21. CPIL, Rate Watchers, Public Advocates, and UCAN are placed on notice that they may be subject to audit or review by the Commission Advisory and Compliance Division pursuant to Rule 76.57; therefore, they shall maintain and retain adequate accounting records and other necessary documentation supporting all claims for

intervenor compensation. They shall maintain such records in a manner that identifies specific issues for which compensation will be requested, the actual time spent by each employee, fees paid to consultants, and any other compensable costs incurred.

This order is effective today.

Dated DEC 19 1988, 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, Executive Director

SAN DIEGO GAS AND ELECTRIC COMPANY

APPENDIX A. Summary of Earnings for Electric, Gas and Steam

APPENDIX B. Attrition 1990-1991 for Electric, Gas and Steam

APPENDIX C. Summary of Electric, Gas and Steam Revenue Changes

<u>Electric</u>

APPENDIX D. Revenue Allocation Detail

APPENDIX E. Marginal Costs

APPENDIX F. Rate Appendix

APPENDIX G. Gas Revenue Allocation and Rates

APPENDIX H. Steam Revenue Allocation and Rates

APPENDIX I. List of Acronyms

SAN DIEGO GAS & ELECTRIC COMPANY
Electric Department
SUMMARY OF EARNINGS AT ADOPTED PRESENT RATE
REVENUES AND EXPENSES
(Thousands Of 1989 Dollars Unless Otherwise Indicated)
Test Year 1989

Description	Adopted
Operating Revenues	
Sales to customers	$778,637
Non-Jurisdictional	1,445
Miscellaneous	17,005
Total Operating Revenues	$797,087
Operating Expenses	
Operation & Maintenance	217,499
Nuclear refueling	4,319
Uncollectibles	15,238
Franchise Requirements	1,643
Subtotal (1986 Dollars)	$238,699
Labor Escalation Amount	12,903
Non-Labor Escalation Amount	10,719
Subtotal (1989 Dollars)	$262,321
Depreciation & Amortization	128,580
Nuclear Decommissioning	22,038
Taxes Other Than On Income	37,666
CA Corporation Franchise Tax	23,560
Federal Income Tax	85,471
Total Operating Expenses	$559,635
Net Operating Income	$237,451
Weighted Average Rate Base	$2,178,451
AUTHORIZED RATE OF RETURN	10.90%

Adopted Revenues at Adopted Rates	$797,087
Less: Stipulated Rev. at Present Rates	$888,468
Less: Amort. of Conservation/Load Mgmt. balancing account overcollection	$3,487
AUTHORIZED INCR. IN REVENUE REQUIREMENT	($94,868)

SAN DIEGO GAS & ELECTRIC COMPANY
Gas Department
SUMMARY OF EARNINGS AT ADOPTED PRESENT RATE
REVENUES AND EXPENSES
(Thousands Of 1989 Dollars Unless Otherwise Indicated)
Test Year 1989

Description	Adopted
Operating Revenues	
Sales to customers	$114,259
Interdepartmental	14,051
Miscellaneous	3,152
Total Operating Revenues	$131,462
Operating Expenses	
Operation & Maintenance	48,577
Uncollectibles	2,535
Franchise Requirements	241
Subtotal (1986 Dollars)	$51,353
Labor Escalation Amount	3,301
Non-Labor Escalation Amount	1,995
Subtotal (1989 Dollars)	$56,649
Depreciation & Amortization	23,056
Taxes Other Than On Income	5,516
CA Corporation Franchise Tax	3,833
Federal Income Tax	12,515
Total Operating Expenses	$101,569
Net Operating Income	$29,893
Weighted Average Rate Base	$274,248
AUTHORIZED RATE OF RETURN	10.90%

Adopted Revenues at Adopted Rates	$131,462
Less: Stipulated Rev. at Present Rates	$121,823
Less: Amort. of Conservation/Load Mgmt. balancing account overcollection	$1,323
AUTHORIZED INCR. IN REVENUE REQUIREMENT	$8,316

SAN DIEGO GAS & ELECTRIC COMPANY
Steam Department
SUMMARY OF EARNINGS AT ADOPTED PRESENT RATE
REVENUES AND EXPENSES
(Thousands Of 1989 Dollars Unless Otherwise Indicated)
Test Year 1989

Description	Adopted
Operating Revenues	
Sales to customers	$1,454
Miscellaneous	0
Total Operating Revenues	$1,454
Operating Expenses	
Operation & Maintenance	1,182
Uncollectibles	28
Franchise Requirements	0
Subtotal (1986 Dollars)	$1,210
Labor Escalation Amount	80
Non-Labor Escalation Amount	62
Subtotal (1989 Dollars)	$1,352
Depreciation & Amortization	39
Taxes Other Than On Income	46
CA Corporation Franchise Tax	(3)
Federal Income Tax	(6)
Total Operating Expenses	$1,428
Net Operating Income	$25
Weighted Average Rate Base	$233
AUTHORIZED RATE OF RETURN	10.90%
Adopted Revenues at Adopted Rates	$1,454
Less: Stipulated Rev. at Present Rates	$954
AUTHORIZED INCR. IN REVENUE REQUIREMENT	$500

SAN DIEGO GAS & ELECTRIC COMPANY
Electric Department - BASE RATE REVENUES
Gas Department - BASE COST AMOUNT
Steam Department - BASE RATE REVENUES
(Thousands Of 1989 Dollars Unless Otherwise Indicated)
Test Year 1989

Electric Department

Adopted Revenues at Adopted Rates	$797,087
Less: Non-Jurisdictional Revenues	1,445
Less: Miscellaneous Revenues	17,005
Less: Amort. of Conservation/Load Mgmt. balancing account overcollection	3,487
AUTHORIZED BASE RATE REVENUES	$775,150
Less: Auth. Base Rate Rev. eff. 4/1/88	764,701
ADOPTED INCREASE IN BASE RATE REVENUES	$10,448
% INCREASE IN BASE RATE REVENUES	1.37%

Gas Department

Adopted Revenues at Adopted Rates	$131,462
Less: Amort. of Conservation/Load Mgmt. balancing account overcollection	1,323
AUTHORIZED BASE COST AMOUNT	$130,139
Less: Base Cost Amount eff. 1/1/88	118,448
ADOPTED INCREASE IN BASE COST AMOUNT	$11,690
% INCREASE IN BASE COST AMOUNT	9.87%

Steam Department

AUTHORIZED BASE RATE REVENUES	$1,454
Less: Auth. Base Rate Rev. eff. 1/1/88	1,831
ADOPTED INCREASE IN BASE RATE REVENUES	($377)
% INCREASE IN BASE RATE REVENUES	-20.59%

SAN DIEGO GAS & ELECTRIC COMPANY
ESCALATION FACTORS - Total Company
COST OF CAPITAL - CPUC Jurisdiction
NET-TO-GROSS MULTIPLIERS
Test Year 1989

Description		Adopted
LABOR ------------> ESCALATION FACTORS	1987	3.970%
	1988	3.805%
	1989	4.201%
	1990	4.816%
	1991	4.932%
NON-LABOR --------> ESCALATION FACTORS	1987	2.625%
	1988	4.986%
	1989	4.719%
	1990	5.086%
	1991	5.334%
OTHER ------------>	ALL YEARS	0.000%

COMPOSITE ESCALATION FACTORS

LABOR	1986 TO 1989	12.460%
NON-LABOR	1986 TO 1989	12.826%
OTHER	1986 TO 1989	0.000%

	Electric Dept.	Gas Dept.	Steam Dept.
Uncollectibles	0.019570	0.022190	0.019570
Franchise Fee	0.002110	0.002110	0.000000
State Inc. Tax	0.093000	0.093000	0.093000
Fed. Inc. Tax	0.340000	0.340000	0.340000
FF&U Factor	1.022117	1.024856	1.019961
Inc.Tax Factor	1.670509	1.670509	1.670509
N-T-G Multipli	1.707456	1.712031	1.703853

	COST	CAPITALIZATION	WTD. COST
Debt	9.23%	45.75%	4.22%
Pref. Stock	6.97%	6.25%	0.44%
Common equity	13.00%	48.00%	6.24%
Auth. Return on Rate Base (CPUC Jurisdiction) :			10.90%

(END OF APPENDIX A)

SAN DIEGO GAS & ELECTRIC COMPANY
Electric Department
ATTRITION YEAR 1990

	Expenses for AY1990 in 000's of 1989$	Expenses for AY1990 in 000's of 1989$ (Calif.)	Transfer of Other Expenses to Labor/ Non-Labor	Expenses for AY1990 in 000's of 1989$ for Attrition purposes
	A D O P T E D	I N	G R C	
Oper. & Maint. Expenses (Juris. Alloc. Factor =				**1.0000)**
Labor	116,113	116,113	0	116,113
Non Labor	89,761	89,761	21,190	110,951
Other	34,694	34,694	(21,190)	13,504
	240,568	240,568	0	240,568
Uncollectibles (Juris. Alloc. Factor =				**1.0000)**
Labor	0	0	0	0
Non Labor	0	0	0	0
Other	15,238	15,238	0	15,238
	15,238	15,238	0	15,238
Franchise Fees (Juris. Alloc. Factor =				**1.0000)**
Labor	0	0	0	0
Non Labor	0	0	0	0
Other	1,643	1,643	0	1,643
	1,643	1,643	0	1,643
TOTAL O&M EXPENSES				
Labor	116,113	116,113	0	116,113
Non Labor	89,761	89,761	21,190	110,951
Other	51,575	51,575	(21,190)	30,385
	257,449	257,449	0	257,449

Labor Base for AY 1990 in 1989$ (Adopted in GRC)	$116,113	
1989 Labor Escalation (estimated in GRC)	4.20%	
1988 Labor Escalation (estimated in GRC)	3.81%	
1987 Labor Escalation (estimated in GRC)	3.97%	
1987 Labor Escalation (use recorded)	3.97%	
1988 Labor Escalation (use recorded)	3.81%	
1989 Labor Escalation (use updated estimate)	4.20%	
1990 Labor Escalation (use updated estimate)	4.82%	
Labor Base for AY 1990 in 1990$	121,705	
Labor Escalation for AY 1990 in 1990$	5,592	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.022117	
Increase in Revenue Requirement	5,716	(1)
Non-Labor Base for AY 1990 in 1989$ (Adopted in GRC	110,951	
1989 Non-Labor Escalation (estimated in GRC)	4.72%	
1988 Non-Labor Escalation (estimated in GRC)	4.99%	
1987 Non-Labor Escalation (estimated in GRC)	2.63%	
1987 Non-Labor Escalation (recorded)	2.63%	
1988 Non-Labor Escalation (recorded)	4.99%	
1989 Non-Labor Escalation (use updated estimate)	4.72%	
1990 Non-Labor Escalation (use updated estimate)	5.09%	
Non-Labor Base for AY 1990 in 1990$	116,594	
Non-Labor Escalation for AY 1990 in 1990$	5,643	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.022117	
Increase in Revenue Requirement	5,768	(2)
Nuclear Refueling Exp. (Juris. Alloc. Factor =	1.0000)	
Labor Base for AY 1990 in 1989$ (Adopted in GRC)	342	
1989 Labor Escalation (estimated in GRC)	4.20%	
1988 Labor Escalation (estimated in GRC)	3.81%	
1987 Labor Escalation (estimated in GRC)	3.97%	
1987 Labor Escalation (use recorded)	3.97%	
1988 Labor Escalation (use recorded)	3.81%	
1989 Labor Escalation (use updated estimate)	4.20%	
1990 Labor Escalation (use updated estimate)	4.82%	
Labor Base for AY 1990 in 1990$	358	
Labor Escalation for AY 1990 in 1990$	16	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.022117	
Increase in Revenue Requirement	17	(3)

Addl. Labor Base for AY 1990 in 1986$ (use updated	(10)	
1987 Labor Escalation (use recorded)	3.97%	
1988 Labor Escalation (use recorded)	3.81%	
1989 Labor Escalation (use updated estimate)	4.20%	
1990 Labor Escalation (use updated estimate)	4.82%	
Additional Labor Base for AY 1990 in 1990$	(12)	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.022117	
Increase in Revenue Requirement	(12)	(4)
Non-Labor Base for AY 1990 in 1989$ (Adopted in GRC	4,530	
1989 Non-Labor Escalation (estimated in GRC)	4.72%	
1988 Non-Labor Escalation (estimated in GRC)	4.99%	
1987 Non-Labor Escalation (estimated in GRC)	2.63%	
1987 Non-Labor Escalation (recorded)	2.63%	
1988 Non-Labor Escalation (recorded)	4.99%	
1989 Non-Labor Escalation (use updated estimate)	4.72%	
1990 Non-Labor Escalation (use updated estimate)	5.09%	
Non-Labor Base for AY 1990 in 1990$	4,761	
Non-Labor Escalation for AY 1990 in 1990$	230	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.022117	
Increase in Revenue Requirement	236	(5)
Addl. Non-Labor Base for AY 1990 in 1986$ (use upda	1,893	
1987 Non-Labor Escalation (recorded)	2.63%	
1988 Non-Labor Escalation (recorded)	4.99%	
1989 Non-Labor Escalation (use updated estimate)	4.72%	
1990 Non-Labor Escalation (use updated estimate)	5.09%	
Additional Non-Labor Base for AY 1990 in 1990$	2,244	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.022117	
Increase in Revenue Requirement	2,294	(6)
Depr. + Nucl. Decomm. Exp. (Juris. Alloc. Factor =	1.0000)	
System avg. Depreciation Rate (Adopted in GRC)	3.7262%	
Increase in Wtd. Avg. Plant in Service for AY1990 (Adopted in GRC)	179,924	
Increase in Depreciation expense	6,704	
Increase in Depreciation expense (Calif.)	6,704	
Net-to-Gross Multiplier (Adopted in GRC)	1.707456	
Increase in Revenue Requirement	11,447	(7)

Ad Valorem Taxes (Juris. Alloc. Factor =		1.0000)	
System avg. Ad Valorem Tax Rate (Adopted in GRC)		0.9350%	
Increase in AY1990 EOY Plant in Service from TY1989 EOY Plant in Service at a wtd-to-net ratio of 0.4495 (Adopted in GRC)		165,775	
Increase in Ad Valorem Taxes		1,550	
Increase in Ad Valorem Taxes (Calif.)		1,550	
Uncoll. & Franchise Fee Factor (Adopted in GRC)		1.022117	
Increase in Revenue Requirement		1,584	(8)
Accel. Amort. (Juris. Alloc. Factor =		1.0000)	
Attrition Year 1990 (Adopted in GRC)		0	
Test Year 1989 (Adopted in GRC)		0	
Increase in Accel. Amortization		0	
Increase in Accel. Amortization (Calif.)		0	
Net-to-Gross Multiplier (Adopted in GRC)		1.707456	
Increase in Revenue Requirement		0	(9)
State Tax Depr. (Juris. Alloc. Factor =		1.0000)	
State Tax Depr. Rate (Adopted in GRC)		3.7971%	
Increase in AY1990 EOY Plant in Service from TY1989 EOY Plant in Service at a wtd-to-net ratio of 0.4495 (Adopted in GRC)		165,775	
Increase in State Tax Depreciation		6,295	
Increase in State Tax Depreciation (Calif.)		6,295	
Increase in CCFT (Tax Rate =	9.3000%	(585)	
Increase in FIT (Tax Rate =	34.0000%	199	
Increase in State & Federal Taxes		(386)	
Net-to-Gross Multiplier (Adopted in GRC)		1.707456	
Increase in Revenue Requirement		(660)	(10)

Federal Tax Depr. (Juris. Alloc. Factor =		1.0000)	
Federal Tax Depr. Rate (Adopted in GRC)		2.7280%	
Increase in AY1990 EOY Plant in Service from TY1989 EOY Plant in Service at a wtd-to-net ratio of 0.4495 (Adopted in GRC)		165,775	
Increase in Federal Tax Depreciation		4,522	
Increase in Federal Tax Depreciation (Calif.)		4,522	
Increase in Federal Taxes (Tax Rate	34.0000%	(1,538)	
Net-to-Gross Multiplier (Adopted in GRC)		1.707456	
Increase in Revenue Requirement		(2,625)	(11)
ITC Normalized (Juris. Alloc. Factor = (Applicable to IRC Sec. 46(f)(2) utilities only.)		1.0000)	
Attrition Year 1990 (Adopted in GRC)		(4,681)	
Test Year 1989 (Adopted in GRC)		(4,681)	
Increase in ITC normalized		0	
Increase in ITC normalized (Calif.)		0	
Net-to-Gross Multiplier (Adopted in GRC)		1.707456	
Increase in Revenue Requirement		0	(12)
Interest Synchro. (Juris. Alloc. Factor = (Applicable to IRC Sec. 46(f)(2) utilities only.)		1.0000)	
ITC Normalized in TY1989 (from above)		4,681	
Wtd. cost of Long Term Debt (Adopted in AY1990)		4.22%	
Increase in CCFT interest		198	
Increase in CCFT (Tax Rate =	9.3000%	(18)	
Increase in FIT (Tax Rate =	34.0000%	6	
Increase in State & Federal Taxes		(12)	
Increase in State & Federal Taxes (Calif.)		(12)	
Net-to-Gross Multiplier (Adopted in GRC)		1.707456	
Increase in Revenue Requirement		(21)	(13)

Rate Base (Juris. Alloc. Factor =	1.0000)
Wtd. avg. Depr Rate Base for TY1989 (Adopted in GRC	2,178,451
Plant in Service (Adopted in GRC)	
Wtd. avg. Additions for TY1989	(84,576)
Net Additions for TY1989	189,984
Wtd. avg. Additions for AY1990	74,516
PHFU (Adopted in GRC)	
Wtd. avg. Additions for TY1989	0
Net Additions for TY1989	0
Wtd. avg. Additions for AY1990	0
Depreciation Reserve (Adopted in GRC)	
Wtd. avg. Depreciation Reserve for TY1989	990,633
Wtd. avg. Depreciation Reserve for AY1990	(1,114,496)
Taxes Deferred - ACRS (Adopted in GRC)	
Wtd. avg. Deferred Taxes - MACRS for TY1989	207,459
Wtd. avg. Deferred Taxes - MACRS for AY1990	(229,244)
Amortization & Other Reserves (Adopted in GRC)	
Weighted average for TY1989	9,593
Weighted average for AY1990	(11,950)
Wtd. avg. Depr Rate Base for AY1990	2,210,370
Wtd. avg. Depr. Rate Base in TY1989 (Adopted in GRC	2,178,451
Wtd. avg. Depr. Rate Base in AY1990 (Adopted in GRC	2,210,370
Wtd. avg. Depr. Rate Base in TY 1989 (Calif.)	2,178,451
Wtd. avg. Depr. Rate Base in AY 1990 (Calif.)	2,210,370

Long-term Debt		
Return on Debt in TY 1989 (Adopted in GRC)	9.23%	
Debt capitalization in TY 1989 (Adopted in GRC)	45.75%	
Wtd. cost of Debt for Test Year 1989	4.22%	
Return on Debt in AY 1990 (Adopted in AY1989)	9.23%	
Debt capitalization in AY 1990 (Adopted in AY1989)	45.75%	
Wtd. cost of Debt for Attrition Year 1990	4.22%	
Increase in Debt cost in Attrition Year 1990	1,347	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.022117	
Increase in Revenue Requirement	1,377	(14)

Preferred Stock

Return on Pref. Stock in TY 1989 (Adopted in GRC)	6.97%	
Pref.Stk. capitalization in TY1989 (Adopted in GRC)	6.25%	
Wtd. cost of Preferred Stock for Test Year 1989	0.44%	
Return on Pref. Stock in AY1990 (Adopted in AY1990)	6.97%	
Pref.Stk. capitalization AY1990 (Adopted in AY1990)	6.25%	
Wtd. cost of Preferred Stock for Att. Year 1990	0.44%	
Increase in Pref. Stock cost in Att. Year 1990	140	
Net-to-Gross Multiplier (Adopted in GRC)	1.707456	
Increase in Revenue Requirement	240	(15)

Common Equity

Return on Common Equity in TY 1989 (Adopted in GRC)	13.00%	
Com. Equity capitalization TY 1989 (Adopted in GRC)	48.00%	
Wtd. cost of Common Equity for Test Year 1989	6.24%	
Return on Common Equity AY 1990 (Adopted in AY1990)	13.00%	
Com. Eq. capitalization AY 1990 (Adopted in AY1990)	48.00%	
Wtd. cost of Common Equity for Att. Year 1990	6.24%	
Increase in Common Equity cost in Att. Year 1990	1,992	
Net-to-Gross Multiplier (Adopted in GRC)	1.707456	
Increase in Revenue Requirement	3,401	(16)

RD&D expense (CIEE funding)

Attrition Year 1990 (Adopted in GRC)	225	
Test Year 1989 (Adopted in GRC)	100	
Increase in RD&D expense	125	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.022117	
Increase in Revenue Requirement	128	(17)

RATEBASE MONITORING

Wtd. avg. Depr.RateBase in TY1989 (Adopted in GRC)	2,178,451
Wtd. avg. Depr.RateBase in TY1989 (use updated est.	2,178,451
Wtd. avg. Depr.RateBase in AY1990 (Adopted in GRC)	2,210,370
Wtd. avg. Depr.RateBase in AY1990 (use updated est.	2,210,370

SAN DIEGO GAS & ELECTRIC COMPANY
Electric Department
REVENUE REQUIREMENTS FOR ATTRITION YEAR 1990
Thousands Of 1990$

ITEM	ATTRITION YEAR 1990	
O & M EXPENSES :		
Labor Escalation	$5,716	(1)
Non-Labor Escalation	5,768	(2)
Total O&M Expenses	11,483	
NUCLEAR REFUELING EXPENSES :		
Labor Escalation	17	(3)
Additional Labor Base	(12)	(4)
Non-Labor Escalation	236	(5)
Additional Non-Labor Base	2,294	(6)
Total Nuclear Refueling Expenses	2,534	
CAPITAL RELATED ITEMS :		
Book Depreciation Expenses	11,447	(7)
Ad Valorem Taxes	1,584	(8)
Accelerated Amortization	0	(9)
State Tax Depreciation	(660)	(10)
Federal Tax Depreciation	(2,625)	(11)
ITC normalized	0	(12)
Interest Synchronization	(21)	(13)
Debt cost	1,377	(14)
Preferred Stock cost	240	(15)
Common Equity cost	3,401	(16)
Total Capital Related Items	14,743	
OTHER AUTHORIZED ITEMS :		
RD&D expense (CIEE funding)	128	(17)
Retirement of debt (Adopted in AY 1990)	(0)	
Book Depreciation exp. adj. (Adopted in AY1990)	0	
Incr. in Non-Jurisdictional Rev. (Adopted in GRC	0	
Amort. of CIMAC bal. account (Adopted in AY1990)	(0)	
SONGS 2&3 post-COD disallowance (Adopted in D.88-12-033)	(0)	
SONGS2&3 pre-COD AFUDCdisallowance(Adopted in D.88-12-033)	(0)	
Total Other Authorized Items	128	
ADD'L REVENUE REQUIREMENTS ---->	$28,889	
Exclude % attributable to Large Light & Power (To be adopted in OIR 86-10-001)	0.00%	
TOTAL ADD'L REVENUE REQUIREMENTS ---->	28,889	

SAN DIEGO GAS & ELECTRIC COMPANY
Electric Department
ATTRITION YEAR 1991

Labor Base

Total Labor Base for AY1991 (adopted in AY 1990)	121,705	
1990 Labor Escalation (estimated in AY1990)	4.82%	
1989 Labor Escalation (estimated in AY1990)	4.20%	
1989 Labor Escalation (use recorded)	4.20%	
1990 Labor Escalation (use updated estimate)	4.82%	
1991 Labor Escalation (use updated estimate)	4.93%	
Labor Base for AY 1991 in 1991$	127,707	
Labor Escalation for AY 1991 in 1991$	6,002	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.022117	
Increase in Revenue Requirement	6,135	(18)

Non-Labor Base

Non-Labor Base for AY 1990 (adopted in AY1990)	$116,594	
1990 Non-Labor Escalation (estimated in AY1990)	5.09%	
1989 Non-Labor Escalation (estimated in AY1990)	4.72%	
1989 Non-Labor Escalation (use recorded)	4.72%	
1990 Non-Labor Escalation (use updated estimate)	5.09%	
1991 Non-Labor Escalation (use updated estimate)	5.33%	
Non-Labor Base for AY 1991 in 1991$	122,813	
Non-Labor Escalation for AY 1991 in 1991$	6,219	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.022117	
Increase in Revenue Requirement	6,357	(19)

Nuclear Refueling Exp. (Juris. Alloc. Factor = 1.0000)

Labor Base for AY 1991 in 1990$ (Adopted in AY1990)	347	
1990 Labor Escalation (estimated in GRC)	4.82%	
1989 Labor Escalation (estimated in GRC)	4.20%	
1989 Labor Escalation (use recorded)	4.20%	
1990 Labor Escalation (use updated estimate)	4.82%	
1991 Labor Escalation (use updated estimate)	4.93%	
Labor Base for AY 1991 in 1991$	364	
Labor Escalation for AY 1991 in 1991$	17	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.022117	
Increase in Revenue Requirement	17	(20)

Addl. Labor Base for AY 1991 in 1986$ (Adopted in AY 1991)	7	
1987 Labor Escalation (use recorded)	3.97%	
1988 Labor Escalation (use recorded)	3.81%	
1989 Labor Escalation (use updated estimate)	4.20%	
1990 Labor Escalation (use updated estimate)	4.82%	
1991 Labor Escalation (use updated estimate of	4.93%	
Additional Labor Base for AY 1991 in 1991$	9	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.022117	
Increase in Revenue Requirement	9	(21)
Non-Labor Base for AY 1991 in 1990$ (Adopted in GRC	7,005	
1990 Non-Labor Escalation (estimated in GRC)	5.09%	
1989 Non-Labor Escalation (estimated in GRC)	4.72%	
1989 Non-Labor Escalation (use recorded)	4.72%	
1990 Non-Labor Escalation (use updated estimate)	5.09%	
1991 Non-Labor Escalation (use updated estimate of	5.33%	
Non-Labor Base for AY 1991 in 1991$	7,378	
Non-Labor Escalation for AY 1991 in 1991$	374	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.022117	
Increase in Revenue Requirement	382	(22)
Addl. Non-Labor Base for AY 1991 in 1986$ (Adopted in AY 1991)	(2,226)	
1987 Non-Labor Escalation (use recorded)	2.63%	
1988 Non-Labor Escalation (use recorded)	4.99%	
1989 Non-Labor Escalation (use updated estimate)	4.72%	
1990 Non-Labor Escalation (use updated estimate)	5.09%	
1991 Non-Labor Escalation (use updated estimate)	5.33%	
Additional Non-Labor Base for AY 1990 in 1990$	(2,780)	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.022117	
Increase in Revenue Requirement	(2,842)	(23)
Depr. + Nucl. Decomm. Exp. (Juris. Alloc. Factor =	1.0000)	
System avg. Depreciation Rate (Adopted in GRC)	3.7262%	
Increase in Wtd. Avg. Plant in Service for AY1991 (Updated in AY 1991)	181,248	
Increase in Depreciation expense	6,754	
Increase in Depreciation expense (Calif.)	6,754	
Net-to-Gross Multiplier (Adopted in GRC)	1.707456	
Increase in Revenue Requirement	11,531	(24)

Ad Valorem Taxes (Juris. Alloc. Factor =	1.0000)	
System avg. Ad Valorem Tax Rate (Adopted in GRC)	0.9350%	
Increase in AY1991 EOY Plant in Service from AY1990 EOY Plant in Service at a wtd-to-net ratio of 0.45798 (Updated in AY1991)	196,491	
Increase in Ad Valorem Taxes	1,837	
Increase in Ad Valorem Taxes (Calif.)	1,837	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.022117	
Increase in Revenue Requirement	1,878	(25)

Accel. Amort. (Juris. Alloc. Factor =	1.0000)	
Attrition Year 1991 (Adopted in GRC)	0	
Attrition Year 1990 (adopted in GRC)	0	
Increase in Accel. Amortization	0	
Increase in Accel. Amortization (Calif.)	0	
Net-to-Gross Multiplier (Adopted in GRC)	1.707456	
Increase in Revenue Requirement	0	(26)

State Tax Depr. (Juris. Alloc. Factor =		1.0000)	
State Tax Depr. Rate (Adopted in GRC)		3.7971%	
Increase in AY1991 EOY Plant in Service from AY1990 EOY Plant in Service at a wtd-to-net ratio of 0.45798 (Updated in AY1991)		196,491	
Increase in State Tax Depreciation		7,461	
Increase in State Tax Depreciation (Calif.)		7,461	
Increase in CCFT (Tax Rate =	9.3000%	(694)	
Increase in FIT (Tax Rate =	34.0000%	236	
Increase in State & Federal Taxes		(458)	
Net-to-Gross Multiplier (Adopted in GRC)		1.707456	
Increase in Revenue Requirement		(782)	(27)

Federal Tax Depr. (Juris. Alloc. Factor =		1.0000)	
Federal Tax Depr. Rate (Adopted in GRC)		2.7280%	
Increase in AY1991 EOY Plant in Service from AY1990 EOY Plant in Service at a wtd-to-net ratio of 0.45798 (Updated in AY1991)		196,491	
Increase in Federal Tax Depreciation		5,360	
Increase in Federal Tax Depreciation (Calif.)		5,360	
Increase in Federal Taxes (Tax Rate	34.0000%	(1,822)	
Net-to-Gross Multiplier (Adopted in GRC)		1.707456	
Increase in Revenue Requirement		(3,112)	(28)

ITC Normalized (Juris. Alloc. Factor =		1.0000)	
(Applicable to IRC Sec. 46(f)(2) utilities only.)			
Attrition Year 1991 (Adopted in GRC)		(4,681)	
Attrition Year 1990 (adopted in GRC)		(4,681)	
Increase in ITC normalized		0	
Increase in ITC normalized (Calif.)		0	
Net-to-Gross Multiplier (Adopted in GRC)		1.707456	
Increase in Revenue Requirement		0	(29)

INTEREST SYNCHRO. (Juris. Alloc. Factor =		1.0000)	
(Applicable to IRC Sec. 46(f)(2) utilities only.))			
ITC Normalized in AY1991 (from above)		4,681	
Wtd. cost of Long Term Debt (Adopted in AY1991)		4.22%	
Increase in CCFT interest		198	
Increase in CCFT (Tax Rate =	9.3000%	(18)	
Increase in FIT (Tax Rate =	34.0000%	6	
Increase in State & Federal Taxes		(12)	
Increase in State & Federal Taxes (Calif.)		(12)	
Net-to-Gross Multiplier (Adopted in GRC)		1.707456	
Increase in Revenue Requirement		(21)	(30)

Rate Base (Juris. Alloc. Factor =	1.0000)
Wtd. avg. Depr Rate Base for AY1990 (Adopted in GRC	2,210,370
Plant in Service (Adopted in GRC)	
Wtd. avg. Additions for AY1990 (Adopted in GRC)	(74,516)
Net Additions for AY1990 (Adopted in GRC)	165,775
Wtd. avg. Additions for AY1991 (Adopted in AY1991)	89,989
PHFU (Adopted in GRC)	
Wtd. avg. Additions for AY1990 (Adopted in GRC)	0
Net Additions for AY1990 (Adopted in GRC)	0
Wtd. avg. Additions for AY1991 (Adopted in AY1991)	0
Depreciation Reserve	
Wtd. avg. Depr. Reserve for AY1990 (Adopted in GRC)	1,114,496
Wtd. avg. Depr. Rsrv. for AY1991 (Updated in AY1991	(1,244,786)
Taxes Deferred - ACRS	
Wtd. avg. Def. Taxes - MACRS for AY1990 (Adopted in	229,244
Wtd. avg. Def. Taxes - MACRS for AY1991 (Updated in	(250,287)
Amortization & Other Reserves (Adopted in GRC)	
Weighted average for AY1990	11,950
Weighted average for AY1991	(14,204)
Wtd. avg. Depr Rate Base for AY1991	2,238,031
Wtd. avg. Depr. Rate Base in Attrition Year 1990	2,210,370
Wtd. avg. Depr. Rate Base in Attrition Year 1991	2,238,031
Wtd. avg. Depr. Rate Base in AY 1990 (Calif.)	2,210,370
Wtd. avg. Depr. Rate Base in AY 1991 (Calif.)	2,238,031
Long-term Debt	
Return on Debt in AY 1990 (Adopted in AY1990)	9.23%
Debt capitalization in AY 1990 (Adopted in AY1990)	45.75%
Wtd. cost of Debt for Attrition Year 1990	4.22%
Return on Debt in AY 1991 (Adopted in AY1991)	9.23%
Debt capitalization in AY 1991 (Adopted in AY1991)	45.75%
Wtd. cost of Debt for Attrition Year 1991	4.22%
Increase in Debt cost in Attrition Year 1991	1,167
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.022117
Increase in Revenue Requirement	1,193

(31)

Preferred Stock

Return on Pref. Stock in AY 1990 (Adopted in AY1990	6.97%	
Pref.Stk. capitalization AY 1990 (Adopted in AY1990	6.25%	
Wtd. cost of Preferred Stock for Test Year 1990	0.44%	
Return on Pref. Stock in AY 1991 (Adopted in AY1991	6.97%	
Pref.Stk. capitalization AY 1991 (Adopted in AY1991	6.25%	
Wtd. cost of Preferred Stock for Att. Year 1991	0.44%	
Increase in Pref. Stock cost in Att. Year 1991	122	
Net-to-Gross Multiplier (Adopted in GRC)	1.707456	
Increase in Revenue Requirement	208	(32)

Common Equity

Return on Com. Eq. in AY 1990 (Adopted in AY1990)	13.00%	
Com. Eq. capitalization AY 1990 (Adopted in AY1990)	48.00%	
Wtd. cost of Common Equity for Test Year 1990	6.24%	
Return on Com. Eq. in AY 1991 (Adopted in AY1991)	13.00%	
Com. Eq. capitalization AY 1991 (Adopted in AY1991)	48.00%	
Wtd. cost of Common Equity for Att. Year 1991	6.24%	
Increase in Common Equity cost in Att. Year 1991	1,726	
Net-to-Gross Multiplier (Adopted in GRC)	1.707456	
Increase in Revenue Requirement	2,947	(33)

RD&D expense (CIEE funding)

Attrition Year 1991 (Adopted in GRC)	350	
Attrition Year 1990 (Adopted in GRC)	225	
Increase in RD&D expense	125	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.022117	
Increase in Revenue Requirement	128	(34)

Retirement of debt

Increase in Revenue Requirement (Adopted in AY1991)	(0)	

RATEBASE TRACKING

Wtd. avg. Depr.Rate Base in TY1989 (Adopted in GRC)	2,178,451
Wtd. avg. Depr.Rate Base in TY1989 (estimated at the time of filing for AY 1990)	2,178,451
Wtd. avg. Depr.Rate Base in TY1989 (recorded)	2,178,451
Wtd. avg. Depr.RateBase in AY1990 (Adopted in GRC)	2,210,370
Wtd. avg. Depr.RateBase in AY1990 (estimated at the time of filing for AY 1990)	2,210,370
Wtd. avg. Depr.RateBase in AY1990 (use updated est.	2,210,370
Wtd. avg. Depr.RateBase in AY1991 (Adopted in GRC)	2,238,031
Wtd. avg. Depr.RateBase in AY1991 (use updated est.	2,238,031

SAN DIEGO GAS & ELECTRIC COMPANY
Electric Department
REVENUE REQUIREMENTS FOR ATTRITION YEAR 1991
Thousands Of 1991$

ITEM	ATTRITION YEAR 1991	
O & M EXPENSES :		
Labor Escalation	$6,135	(18)
Non-Labor Escalation	6,357	(19)
Total O&M Expenses	12,492	
NUCLEAR REFUELING EXPENSES :		
Labor Escalation	17	(20)
Additional Labor Base	9	(21)
Non-Labor Escalation	382	(22)
Additional Non-Labor Base	(2,842)	(23)
Total Nuclear Refueling Expenses	(2,433)	
CAPITAL RELATED ITEMS :		
Book Depreciation Expenses	11,531	(24)
Ad Valorem Taxes	1,878	(25)
Accelerated Amortization	0	(26)
State Tax Depreciation	(782)	(27)
Federal Tax Depreciation	(3,112)	(28)
ITC normalized	0	(29)
Interest Synchronization	(21)	(30)
Debt cost	1,193	(31)
Preferred Stock cost	208	(32)
Common Equity cost	2,947	(33)
Total Capital Related Items	13,843	
OTHER AUTHORIZED ITEMS :		
RD&D expense (CIEE funding)	128	(34)
Retirement of debt (Adopted in AY 1991)	(0)	
Book Depreciation exp. adj. (Adopted in AY1991)	0	
Incr. in Non-Jurisdictional Rev. (Adopted in GRC	0	
Amort. of CLMAC bal. account (Adopted in AY1990)	(0)	
SONGS 2&3 post-COD disallowance (Adopted in D.88-12-033)	(0)	
SONGS2&3 pre-COD AFUDCdisallowance(Adopted in D.88-12-033)	(0)	
Total Other Authorized Items	128	
ADD'L REVENUE REQUIREMENTS ---->	$24,029	
Exclude % attributable to Large Light & Power (To be adopted in OIR 86-10-001)	0.00%	
TOTAL ADD'L REVENUE REQUIREMENTS ---->	24,029	

SAN DIEGO GAS & ELECTRIC COMPANY
Gas Department
ATTRITION YEAR 1990

	Expenses for AY1990 in 000's of 1989$	Expenses for AY1990 in 000's of 1989$ (Calif.)	Transfer of Other Expenses to Labor/ Non-Labor	Expenses for AY1990 in 000's of 1989$ for Attrition purposes
	A D O P T E D	I N	G R C	
Oper. & Maint. Expenses (Juris. Alloc. Factor =				**1.0000)**
Labor	29,790	29,790	0	29,790
Non Labor	17,552	17,552	5,034	22,586
Other	6,531	6,531	(5,034)	1,497
	53,873	53,873	0	53,873
Uncollectibles (Juris. Alloc. Factor =				**1.0000)**
Labor	0	0	0	0
Non Labor	0	0	0	0
Other	2,535	2,535	0	2,535
	2,535	2,535	0	2,535
Franchise Fees (Juris. Alloc. Factor =				**1.0000)**
Labor	0	0	0	0
Non Labor	0	0	0	0
Other	241	241	0	241
	241	241	0	241
TOTAL O&M EXPENSES				
Labor	29,790	29,790	0	29,790
Non Labor	17,552	17,552	5,034	22,586
Other	9,308	9,308	(5,034)	4,274
	56,649	56,649	0	56,649

Labor Base for AY 1990 in 1989$ (Adopted in GRC)	$29,790	
1989 Labor Escalation (estimated in GRC)	4.20%	
1988 Labor Escalation (estimated in GRC)	3.81%	
1987 Labor Escalation (estimated in GRC)	3.97%	
1987 Labor Escalation (use recorded)	3.97%	
1988 Labor Escalation (use recorded)	3.81%	
1989 Labor Escalation (use updated estimate)	4.20%	
1990 Labor Escalation (use updated estimate)	4.84%	
Labor Base for AY 1990 in 1990$	31,232	
Labor Escalation for AY 1990 in 1990$	1,442	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.024856	
Increase in Revenue Requirement	1,478	(35)
Non-Labor Base for AY 1990 in 1989$ (Adopted in GRC	22,586	
1989 Non-Labor Escalation (estimated in GRC)	4.72%	
1988 Non-Labor Escalation (estimated in GRC)	4.99%	
1987 Non-Labor Escalation (estimated in GRC)	2.63%	
1987 Non-Labor Escalation (recorded)	2.63%	
1988 Non-Labor Escalation (recorded)	4.99%	
1989 Non-Labor Escalation (use updated estimate)	4.72%	
1990 Non-Labor Escalation (use updated estimate)	4.87%	
Non-Labor Base for AY 1990 in 1990$	23,685	
Non-Labor Escalation for AY 1990 in 1990$	1,099	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.024856	
Increase in Revenue Requirement	1,126	(36)

Depreciation Exp. (Juris. Alloc. Factor =	1.0000)	
System avg. Depreciation Rate (Adopted in GRC)	4.2481%	
Increase in Wtd. Avg. Plant in Service for AY1990 (Adopted in GRC)	38,795	
Increase in Depreciation expense	1,648	
Increase in Depreciation expense (Calif.)	1,648	
Net-to-Gross Multiplier (Adopted in GRC)	1.712031	
Increase in Revenue Requirement	2,822	(37)

Ad Valorem Taxes (Juris. Alloc. Factor =		1.0000)	
System avg. Ad Valorem Tax Rate (Adopted in GRC)		0.7552%	
Increase in AY1990 EOY Plant in Service from TY1989 EOY Plant in Service at wtd-to-net ratio of 0.44303 (Adopted in GRC)		41,882	
Increase in Ad Valorem Taxes		316	
Increase in Ad Valorem Taxes (Calif.)		316	
Uncoll. & Franchise Fee Factor (Adopted in GRC)		1.024856	
Increase in Revenue Requirement		324	(38)

Accel. Amort. (Juris. Alloc. Factor =		1.0000)	
Attrition Year 1990 (Adopted in GRC)		0	
Test Year 1989 (Adopted in GRC)		0	
Increase in Accel. Amortization		0	
Increase in Accel. Amortization (Calif.)		0	
Net-to-Gross Multiplier (Adopted in GRC)		1.712031	
Increase in Revenue Requirement		0	(39)

State Tax Depr. (Juris. Alloc. Factor =		1.0000)	
State Tax Depr. Rate (Adopted in GRC)		2.9569%	
Increase in AY1990 EOY Plant in Service from TY1989 EOY Plant in Service at wtd-to-net ratio of 0.44303 (Adopted in GRC)		41,882	
Increase in State Tax Depreciation		1,238	
Increase in State Tax Depreciation (Calif.)		1,238	
Increase in CCFT (Tax Rate =	9.3000%	(115)	
Increase in FIT (Tax Rate =	34.0000%	39	
Increase in State & Federal Taxes		(76)	
Net-to-Gross Multiplier (Adopted in GRC)		1.712031	
Increase in Revenue Requirement		(130)	(40)

Federal Tax Depr. (Juris. Alloc. Factor =		1.0000)	
Federal Tax Depr. Rate (Adopted in GRC)		2.8582%	
Increase in AY1990 EOY Plant in Service from TY1989 EOY Plant in Service at wtd-to-net ratio of 0.44303 (Adopted in GRC)		41,882	
Increase in Federal Tax Depreciation		1,197	
Increase in Federal Tax Depreciation (Calif.)		1,197	
Increase in Federal Taxes (Tax Rate	34.0000%	(407)	
Net-to-Gross Multiplier (Adopted in GRC)		1.712031	
Increase in Revenue Requirement		(697)	(41)
ITC Normalized (Juris. Alloc. Factor = (Applicable to IRC Sec. 46(f)(2) utilities only.)		1.0000)	
Attrition Year 1990 (Adopted in GRC)		(345)	
Test Year 1989 (Adopted in GRC)		(345)	
Increase in ITC normalized		0	
Increase in ITC normalized (Calif.)		0	
Net-to-Gross Multiplier (Adopted in GRC)		1.712031	
Increase in Revenue Requirement		0	(42)
Interest Synchronization (Juris. Alloc. Factor = (Applicable to IRC Sec. 46(f)(2) utilities only.)		1.0000)	
ITC Normalized in TY1989 (from above)		345	
Wtd. cost of Long Term Debt (Adopted in AY1990)		4.22%	
Increase in CCFT interest		15	
Increase in CCFT (Tax Rate =	9.3000%	(1)	
Increase in FIT (Tax Rate =	34.0000%	0	
Increase in State & Federal Taxes		(1)	
Increase in State & Federal Taxes (Calif.)		(1)	
Net-to-Gross Multiplier (Adopted in GRC)		1.712031	
Increase in Revenue Requirement		(2)	(43)

Rate Base (Juris. Alloc. Factor =	1.0000
Wtd. avg. Depr Rate Base for TY1989 (Adopted in GRC	274,248
Plant in Service (Adopted in GRC)	
Wtd. avg. Additions for TY1989	(16,767)
Net Additions for TY1989	37,007
Wtd. avg. Additions for AY1990	18,555
PHFU (Adopted in GRC)	
Wtd. avg. Additions for TY1989	0
Net Additions for TY1989	0)
Wtd. avg. Additions for AY1990	0
Depreciation Reserve (Adopted in GRC)	
Wtd. avg. Depreciation Reserve for TY1989	197,332
Wtd. avg. Depreciation Reserve for AY1990	(218,626)
Taxes Deferred - ACRS (Adopted in GRC)	
Wtd. avg. Deferred Taxes - MACRS for TY1989	9,503
Wtd. avg. Deferred Taxes - MACRS for AY1990	(11,142)
Amortization & Other Reserves (Adopted in GRC)	
Weighted average for TY1989	1,225
Weighted average for AY1990	(1,444)
Wtd. avg. Depr Rate Base for AY1990	289,891
Wtd. avg. Depr. Rate Base in TY1989 (Adopted in GRC	274,248
Wtd. avg. Depr. Rate Base in AY1990 (Adopted in GRC	289,891
Wtd. avg. Depr. Rate Base in TY 1989 (Calif.)	274,248
Wtd. avg. Depr. Rate Base in AY 1990 (Calif.)	289,891
Long-term Debt	
Return on Debt in TY 1989 (Adopted in GRC)	9.23%
Debt capitalization in TY 1989 (Adopted in GRC)	45.75%
Wtd. cost of Debt for Test Year 1989	4.22%
Return on Debt in AY 1990 (Adopted in AY1989)	9.23%
Debt capitalization in AY 1990 (Adopted in AY1989)	45.75%
Wtd. cost of Debt for Attrition Year 1990	4.22%
Increase in Debt cost in Attrition Year 1990	660
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.024856
Increase in Revenue Requirement	677 (44)

Preferred Stock

Return on Pref. Stock in TY 1989 (Adopted in GRC)	6.97%	
Pref.Stk. capitalization in TY1989 (Adopted in GRC)	6.25%	
Wtd. cost of Preferred Stock for Test Year 1989	0.44%	
Return on Pref. Stock in AY1990 (Adopted in AY1990)	6.97%	
Pref.Stk. capitalization AY1990 (Adopted in AY1990)	6.25%	
Wtd. cost of Preferred Stock for Att. Year 1990	0.44%	
Increase in Pref. Stock cost in Att. Year 1990	69	
Net-to-Gross Multiplier (Adopted in GRC)	1.712031	
Increase in Revenue Requirement	118	(45)

Common Equity

Return on Common Equity in TY 1989 (Adopted in GRC)	13.00%	
Com. Equity capitalization TY 1989 (Adopted in GRC)	48.00%	
Wtd. cost of Common Equity for Test Year 1989	6.24%	
Return on Common Equity AY 1990 (Adopted in AY1990)	13.00%	
Com. Eq. capitalization AY 1990 (Adopted in AY1990)	48.00%	
Wtd. cost of Common Equity for Att. Year 1990	6.24%	
Increase in Common Equity cost in Att. Year 1990	976	
Net-to-Gross Multiplier (Adopted in GRC)	1.712031	
Increase in Revenue Requirement	1,671	(46)

Retirement of debt

Increase in Revenue Requirement (Adopted in AY1990)	(0)

RATEBASE MONITORING

Wtd. avg. Depr.RateBase in TY1989 (Adopted in GRC)	274,248
Wtd. avg. Depr.RateBase in TY1989 (use updated est.	274,248
Wtd. avg. Depr.RateBase in AY1990 (Adopted in GRC)	289,891
Wtd. avg. Depr.RateBase in AY1990 (use updated est.	289,891

SAN DIEGO GAS & ELECTRIC COMPANY
Gas Department
REVENUE REQUIREMENTS FOR ATTRITION YEAR 1990
Thousands Of 1990$

ITEM	ATTRITION YEAR 1990	
O & M EXPENSES :		
Labor Escalation	$1,478	(35)
Non-Labor Escalation	1,126	(36)
Total O&M Expenses	2,605	
CAPITAL RELATED ITEMS :		
Book Depreciation Expenses	2,822	(37)
Ad Valorem Taxes	324	(38)
Accelerated Amortization	0	(39)
State Tax Depreciation	(130)	(40)
Federal Tax Depreciation	(697)	(41)
ITC normalized	0	(42)
Interest Synchronization	(2)	(43)
Debt cost	677	(44)
Preferred Stock cost	118	(45)
Common Equity cost	1,671	(46)
Total Capital Related Items	4,783	
OTHER AUTHORIZED ITEMS :		
Retirement of debt (Adopted in AY 1990)	(0)	
Book Depreciation exp. adj. (Adopted in AY1990)	0	
Amort. of CIMAC bal. account (Adopted in AY1990)	(0)	
Total Other Authorized Items	(0)	
TOTAL ADD'L REVENUE REQUIREMENTS ---->	$7,387	

SAN DIEGO GAS & ELECTRIC COMPANY
Gas Department
ATTRITION YEAR 1991

Labor Base		
Total Labor Base for AY 1991 in 1990$	31,232	
1990 Labor Escalation (estimated in GRC)	4.84%	
1989 Labor Escalation (estimated in AY1990)	4.20%	
1989 Labor Escalation (use recorded)	4.20%	
1990 Labor Escalation (use updated estimate)	4.84%	
1991 Labor Escalation (use updated estimate)	5.04%	
Labor Base for AY 1991 in 1991$	32,807	
Labor Escalation for AY 1991 in 1991$	1,575	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.024856	
Increase in Revenue Requirement	1,614	(47)
Non-Labor Base		
Non-Labor Base for AY 1990 (Adopted in AY1990)	$23,685	
1990 Non-Labor Escalation (estimated in GRC)	4.87%	
1989 Non-Labor Escalation (estimated in AY1989)	4.72%	
1989 Non-Labor Escalation (use recorded)	4.72%	
1990 Non-Labor Escalation (use updated estimate)	4.87%	
1991 Non-Labor Escalation (use updated estimate)	5.21%	
Non-Labor Base for AY 1991 in 1991$	24,919	
Non-Labor Escalation for AY 1991 in 1991$	1,234	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.024856	
Increase in Revenue Requirement	1,265	(48)
Depreciation Exp. (Juris. Alloc. Factor =	1.0000)	
System avg. Depreciation Rate (Adopted in GRC)	4.2481%	
Increase in Wtd. Avg. Plant in Service for AY1991 (Adopted in GRC)	43,203	
Increase in Depreciation expense	1,835	
Increase in Depreciation expense (Calif.)	1,835	
Net-to-Gross Multiplier (Adopted in GRC)	1.712031	
Increase in Revenue Requirement	3,142	(49)

Ad Valorem Taxes (Juris. Alloc. Factor =		1.0000)	
System avg. Ad Valorem Tax Rate (Adopted in GRC)		0.7552%	
Increase in AY1991 EOY Plant in Service from TY1990 EOY Plant in Service at wtd-to-net ratio of 0.43688 (Adopted in GRC)		45,495	
Increase in Ad Valorem Taxes		344	
Increase in Ad Valorem Taxes (Calif.)		344	
Uncoll. & Franchise Fee Factor (Adopted in GRC)		1.024856	
Increase in Revenue Requirement		352	(50)
Accel. Amort. (Juris. Alloc. Factor =		1.0000)	
Attrition Year 1991 (Adopted in GRC)		0	
Attrition Year 1990 (adopted in GRC)		0	
Increase in Accel. Amortization		0	
Increase in Accel. Amortization (Calif.)		0	
Net-to-Gross Multiplier (Adopted in GRC)		1.712031	
Increase in Revenue Requirement		0	(51)
State Tax Depr. (Juris. Alloc. Factor =		1.0000)	
State Tax Depr. Rate (Adopted in GRC)		2.9569%	
Increase in AY1991 EOY Plant in Service from TY1990 EOY Plant in Service at wtd-to-net ratio of 0.43688 (Adopted in GRC)		45,495	
Increase in State Tax Depreciation		1,345	
Increase in State Tax Depreciation (Calif.)		1,345	
Increase in CCFT (Tax Rate =	9.3000%	(125)	
Increase in FIT (Tax Rate =	34.0000%	43	
Increase in State & Federal Taxes		(83)	
Net-to-Gross Multiplier (Adopted in GRC)		1.712031	
Increase in Revenue Requirement		(141)	(52)

Federal Tax Depr. (Juris. Alloc. Factor =		1.0000)	
Federal Tax Depr. Rate (Adopted in GRC)		2.8582%	
Increase in AY1991 EOY Plant in Service from TY1990 EOY Plant in Service at wtd-to-net ratio of 0.43688 (Adopted in GRC)		45,495	
Increase in Federal Tax Depreciation		1,300	
Increase in Federal Tax Depreciation (Calif.)		1,300	
Increase in Federal Taxes (Tax Rate	34.0000%	(442)	
Net-to-Gross Multiplier (Adopted in GRC)		1.712031	
Increase in Revenue Requirement		(757)	(53)

ITC Normalized (Juris. Alloc. Factor = (Applicable to IRC Sec. 46(f)(2) utilities only.)		1.0000)	
Attrition Year 1991 (Adopted in GRC)		(345)	
Attrition Year 1990 (adopted in GRC)		(345)	
Increase in ITC normalized		0	
Increase in ITC normalized (Calif.)		0	
Net-to-Gross Multiplier (Adopted in GRC)		1.712031	
Increase in Revenue Requirement		0	(54)

INTEREST SYNCHRO. (Juris. Alloc. Factor = (Applicable to IRC Sec. 46(f)(2) utilities only.))		1.0000)	
ITC Normalized in AY1991 (from above)		345	
Wtd. cost of Long Term Debt (Adopted in AY1991)		4.22%	
Increase in CCFT interest		15	
Increase in CCFT (Tax Rate =	9.3000%	(1)	
Increase in FIT (Tax Rate =	34.0000%	0	
Increase in State & Federal Taxes		(1)	
Increase in State & Federal Taxes (Calif.)		(1)	
Net-to-Gross Multiplier (Adopted in GRC)		1.712031	
Increase in Revenue Requirement		(2)	(55)

Rate Base (Juris. Alloc. Factor =	1.0000)
Wtd. avg. Depr Rate Base for AY1990 (Adopted in GRC	289,891
Plant in Service (Adopted in GRC)	
Wtd. avg. Additions for AY1990	(18,555)
Net Additions for AY1990	41,882
Wtd. avg. Additions for AY1991	19,876
PHFU (Adopted in GRC)	
Wtd. avg. Additions for AY1990	0
Net Additions for AY1990	0
Wtd. avg. Additions for AY1991	0
Depreciation Reserve (Adopted in GRC)	
Wtd. avg. Depreciation Reserve for AY1990	218,626
Wtd. avg. Depreciation Reserve for AY1991	(241,615)
Taxes Deferred - ACRS (Adopted in GRC)	
Wtd. avg. Deferred Taxes - MACRS for AY1990	11,142
Wtd. avg. Deferred Taxes - MACRS for AY1991	(12,760)
Amortization & Other Reserves (Adopted in GRC)	
Weighted average for AY1990	1,444
Weighted average for AY1991	(1,663)
Wtd. avg. Depr Rate Base for AY1991	308,268
Wtd. avg. Depr. Rate Base in Attrition Year 1990	289,891
Wtd. avg. Depr. Rate Base in Attrition Year 1991	308,268
Wtd. avg. Depr. Rate Base in AY 1990 (Calif.)	289,891
Wtd. avg. Depr. Rate Base in AY 1991 (Calif.)	308,268
Long-term Debt	
Return on Debt in AY 1990 (Adopted in AY1990)	9.23%
Debt capitalization in AY 1990 (Adopted in AY1990)	45.75%
Wtd. cost of Debt for Attrition Year 1990	4.22%
Return on Debt in AY 1991 (Adopted in AY1991)	9.23%
Debt capitalization in AY 1991 (Adopted in AY1991)	45.75%
Wtd. cost of Debt for Attrition Year 1991	4.22%
Increase in Debt cost in Attrition Year 1991	776
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.024856
Increase in Revenue Requirement	795 (56)

Preferred Stock

Return on Pref. Stock in AY 1990 (Adopted in AY1990	6.97%	
Pref.Stk. capitalization AY 1990 (Adopted in AY1990	6.25%	
Wtd. cost of Preferred Stock for Test Year 1990	0.44%	
Return on Pref. Stock in AY 1991 (Adopted in AY1991	6.97%	
Pref.Stk. capitalization AY 1991 (Adopted in AY1991	6.25%	
Wtd. cost of Preferred Stock for Att. Year 1991	0.44%	
Increase in Pref. Stock cost in Att. Year 1991	81	
Net-to-Gross Multiplier (Adopted in GRC)	1.712031	
Increase in Revenue Requirement	138	(57)

Common Equity

Return on Com. Eq. in AY 1990 (Adopted in AY1990)	13.00%	
Com. Eq. capitalization AY 1990 (Adopted in AY1990)	48.00%	
Wtd. cost of Common Equity for Test Year 1990	6.24%	
Return on Com. Eq. in AY 1991 (Adopted in AY1991)	13.00%	
Com. Eq. capitalization AY 1991 (Adopted in AY1991)	48.00%	
Wtd. cost of Common Equity for Att. Year 1991	6.24%	
Increase in Common Equity cost in Att. Year 1991	1,147	
Net-to-Gross Multiplier (Adopted in GRC)	1.712031	
Increase in Revenue Requirement	1,963	(58)

Retirement of debt

Increase in Revenue Requirement (Adopted in AY1991)	(0)

RATEBASE TRACKING

Wtd. avg. Depr.Rate Base in TY1989 (Adopted in GRC)	274,248
Wtd. avg. Depr.Rate Base in TY1989 (estimated at the time of filing for AY 1990)	274,248
Wtd. avg. Depr.Rate Base in TY1989 (recorded)	274,248
Wtd. avg. Depr.RateBase in AY1990 (Adopted in GRC)	289,891
Wtd. avg. Depr.RateBase in AY1990 (estimated at the time of filing for AY 1990)	289,891
Wtd. avg. Depr.RateBase in AY1990 (use updated est.	289,891
Wtd. avg. Depr.RateBase in AY1991 (Adopted in GRC)	308,268
Wtd. avg. Depr.RateBase in AY1991 (use updated est.	308,268

SAN DIEGO GAS & ELECTRIC COMPANY
Gas Department
REVENUE REQUIREMENTS FOR ATTRITION YEAR 1991
Thousands Of 1991$

ITEM	ATTRITION YEAR 1991	
O & M EXPENSES :		
Labor Escalation	$1,614	(47)
Non-Labor Escalation	1,265	(48)
Total O&M Expenses	2,879	
CAPITAL RELATED ITEMS :		
Book Depreciation Expenses	3,142	(49)
Ad Valorem Taxes	352	(50)
Accelerated Amortization	0	(51)
State Tax Depreciation	(141)	(52)
Federal Tax Depreciation	(757)	(53)
ITC normalized	0	(54)
Interest Synchronization	(2)	(55)
Debt cost	795	(56)
Preferred Stock cost	138	(57)
Common Equity cost	1,963	(58)
Total Capital Related Items	5,491	
OTHER AUTHORIZED ITEMS :		
Retirement of debt (Adopted in AY 1991)	(0)	
Book Depreciation exp. adj. (Adopted in AY1991)	0	
Amort. of CIMAC bal. account (Adopted in AY1990)	(0)	
Total Other Authorized Items	(0)	
TOTAL ADD'L REVENUE REQUIREMENTS ---->	$8,370	

SAN DIEGO GAS & ELECTRIC COMPANY
Steam Department
ATTRITION YEAR 1990

	Expenses for AY1990 in 000's of 1989$	Expenses for AY1990 in 000's of 1989$ (Calif.)	Transfer of Other Expenses to Labor/ Non-Labor	Expenses for AY1990 in 000's of 1989$ for Attrition purposes
	A D O P T E D	I N	G R C	
Oper. & Maint. Expenses (Juris. Alloc. Factor =				**1.0000)**
Labor	725	725	0	725
Non Labor	542	542	54	596
Other	57	57	(54)	3
	1,324	1,324	0	1,324
Uncollectibles (Juris. Alloc. Factor =				**1.0000)**
Labor	0	0	0	0
Non Labor	0	0	0	0
Other	28	28	0	28
	28	28	0	28
Franchise Fees (Juris. Alloc. Factor =				**1.0000)**
Labor	0	0	0	0
Non Labor	0	0	0	0
Other	0	0	0	0
	0	0	0	0
TOTAL O&M EXPENSES				
Labor	725	725	0	725
Non Labor	542	542	54	596
Other	85	85	(54)	31
	1,352	1,352	0	1,352

Labor Base for AY 1990 in 1989$ (Adopted in GRC)	$725	
1989 Labor Escalation (estimated in GRC)	4.20%	
1988 Labor Escalation (estimated in GRC)	3.81%	
1987 Labor Escalation (estimated in GRC)	3.97%	
1987 Labor Escalation (use recorded)	3.97%	
1988 Labor Escalation (use recorded)	3.81%	
1989 Labor Escalation (use updated estimate)	4.20%	
1990 Labor Escalation (use updated estimate)	4.84%	
Labor Base for AY 1990 in 1990$	760	
Labor Escalation for AY 1990 in 1990$	35	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.019961	
Increase in Revenue Requirement	36	(59)
Non-Labor Base for AY 1990 in 1989$ (Adopted in GRC	596	
1989 Non-Labor Escalation (estimated in GRC)	4.72%	
1988 Non-Labor Escalation (estimated in GRC)	4.99%	
1987 Non-Labor Escalation (estimated in GRC)	2.63%	
1987 Non-Labor Escalation (recorded)	2.63%	
1988 Non-Labor Escalation (recorded)	4.99%	
1989 Non-Labor Escalation (use updated estimate)	4.72%	
1990 Non-Labor Escalation (use updated estimate)	4.87%	
Non-Labor Base for AY 1990 in 1990$	625	
Non-Labor Escalation for AY 1990 in 1990$	29	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.019961	
Increase in Revenue Requirement	30	(60)
Depreciation Exp. (Juris. Alloc. Factor =	1.0000)	
System avg. Depreciation Rate (Adopted in GRC)	0.7244%	
Increase in Wtd. Avg. Plant in Service for AY1990 (Adopted in GRC)	30	
Increase in Depreciation expense	0	
Increase in Depreciation expense (Calif.)	0	
Net-to-Gross Multiplier (Adopted in GRC)	1.703853	
Increase in Revenue Requirement	0	(61)

Ad Valorem Taxes (Juris. Alloc. Factor =	1.0000)	
System avg. Ad Valorem Tax Rate (Adopted in GRC)	0.1483%	
Increase in AY1990 EOY Plant in Service from TY1989 EOY Plant in Service at wtd-to-net ratio of 0.3081 (Adopted in GRC)	57	
Increase in Ad Valorem Taxes	0	
Increase in Ad Valorem Taxes (Calif.)	0	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.019961	
Increase in Revenue Requirement	0	(62)
Accel. Amort. (Juris. Alloc. Factor =	1.0000)	
Attrition Year 1990 (Adopted in GRC)	0	
Test Year 1989 (Adopted in GRC)	0	
Increase in Accel. Amortization	0	
Increase in Accel. Amortization (Calif.)	0	
Net-to-Gross Multiplier (Adopted in GRC)	1.703853	
Increase in Revenue Requirement	0	(63)
State Tax Depr. (Juris. Alloc. Factor =	1.0000)	
State Tax Depr. Rate (Adopted in GRC)	1.4362%	
Increase in AY1990 EOY Plant in Service from TY1989 EOY Plant in Service at wtd-to-net ratio of 0.3081 (Adopted in GRC)	57	
Increase in State Tax Depreciation	1	
Increase in State Tax Depreciation (Calif.)	1	
Increase in CCFT (Tax Rate = 9.3000%	(0)	
Increase in FIT (Tax Rate = 34.0000%	0	
Increase in State & Federal Taxes	(0)	
Net-to-Gross Multiplier (Adopted in GRC)	1.703853	
Increase in Revenue Requirement	(0)	(64)

Federal Tax Depr. (Juris. Alloc. Factor =		1.0000)	
Federal Tax Depr. Rate (Adopted in GRC)		1.2185%	
Increase in AY1990 EOY Plant in Service from TY1989 EOY Plant in Service at wtd-to-net ratio of 0.3081 (Adopted in GRC)		57	
Increase in Federal Tax Depreciation		1	
Increase in Federal Tax Depreciation (Calif.)		1	
Increase in Federal Taxes (Tax Rate	34.0000%	(0)	
Net-to-Gross Multiplier (Adopted in GRC)		1.703853	
Increase in Revenue Requirement		(0)	(65)

ITC Normalized (Juris. Alloc. Factor = (Applicable to IRC Sec. 46(f)(2) utilities only.)		1.0000)	
Attrition Year 1990 (Adopted in GRC)		0	
Test Year 1989 (Adopted in GRC)		0	
Increase in ITC normalized		0	
Increase in ITC normalized (Calif.)		0	
Net-to-Gross Multiplier (Adopted in GRC)		1.703853	
Increase in Revenue Requirement		0	(66)

Interest Synchronization (Juris. Alloc. Factor = (Applicable to IRC Sec. 46(f)(2) utilities only.)		1.0000)	
ITC Normalized in TY1989 (from above)		0	
Wtd. cost of Long Term Debt (Adopted in AY1990)		3.74%	
Increase in CCFT interest		0	
Increase in CCFT (Tax Rate =	9.3000%	0	
Increase in FIT (Tax Rate =	34.0000%	0	
Increase in State & Federal Taxes		0	
Increase in State & Federal Taxes (Calif.)		0	
Net-to-Gross Multiplier (Adopted in GRC)		1.703853	
Increase in Revenue Requirement		0	(67)

Rate Base (Juris. Alloc. Factor =	1.0000)
Wtd. avg. Depr Rate Base for TY1989 (Adopted in GRC	233
Plant in Service (Adopted in GRC)	
Wtd. avg. Additions for TY1989	(3)
Net Additions for TY1989	15
Wtd. avg. Additions for AY1990	18
PHFU (Adopted in GRC)	
Wtd. avg. Additions for TY1989	0
Net Additions for TY1989	0
Wtd. avg. Additions for AY1990	0
Depreciation Reserve (Adopted in GRC)	
Wtd. avg. Depreciation Reserve for TY1989	5,166
Wtd. avg. Depreciation Reserve for AY1990	(5,205)
Taxes Deferred - ACRS (Adopted in GRC)	
Wtd. avg. Deferred Taxes - MACRS for TY1989	77
Wtd. avg. Deferred Taxes - MACRS for AY1990	(87)
Taxes Deferred - Amort & Other (Adopted in GRC)	
Wtd. avg. Deferred Taxes - Amort & Other for TY1989	2
Wtd. avg. Deferred Taxes - Amort & Other for AY1990	(2)
Wtd. avg. Depr Rate Base for AY1990	214
Wtd. avg. Depr. Rate Base in TY1989 (Adopted in GRC	233
Wtd. avg. Depr. Rate Base in AY1990 (Adopted in GRC	214
Wtd. avg. Depr. Rate Base in TY 1989 (Calif.)	233
Wtd. avg. Depr. Rate Base in AY 1990 (Calif.)	214

Long-term Debt		
Return on Debt in TY 1989 (Adopted in GRC)	9.24%	
Debt capitalization in TY 1989 (Adopted in GRC)	40.50%	
Wtd. cost of Debt for Test Year 1989	3.74%	
Return on Debt in AY 1990 (Adopted in AY1989)	9.24%	
Debt capitalization in AY 1990 (Adopted in AY1989)	40.50%	
Wtd. cost of Debt for Attrition Year 1990	3.74%	
Increase in Debt cost in Attrition Year 1990	(1)	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.019961	
Increase in Revenue Requirement	(1)	(68)

Preferred Stock

Return on Pref. Stock in TY 1989 (Adopted in GRC)	7.28%	
Pref.Stk. capitalization in TY1989 (Adopted in GRC)	8.50%	
Wtd. cost of Preferred Stock for Test Year 1989	0.62%	
Return on Pref. Stock in AY1990 (Adopted in AY1990)	7.28%	
Pref.Stk. capitalization AY1990 (Adopted in AY1990)	8.50%	
Wtd. cost of Preferred Stock for Att. Year 1990	0.62%	
Increase in Pref. Stock cost in Att. Year 1990	(0)	
Net-to-Gross Multiplier (Adopted in GRC)	1.703853	
Increase in Revenue Requirement	(0)	(69)

Common Equity

Return on Common Equity in TY 1989 (Adopted in GRC)	12.75%	
Com. Equity capitalization TY 1989 (Adopted in GRC)	51.00%	
Wtd. cost of Common Equity for Test Year 1989	6.50%	
Return on Common Equity AY 1990 (Adopted in AY1990)	12.75%	
Com. Eq. capitalization AY 1990 (Adopted in AY1990)	51.00%	
Wtd. cost of Common Equity for Att. Year 1990	6.50%	
Increase in Common Equity cost in Att. Year 1990	(1)	
Net-to-Gross Multiplier (Adopted in GRC)	1.703853	
Increase in Revenue Requirement	(2)	(70)

Retirement of debt

Increase in Revenue Requirement (Adopted in AY1990)	(0)

RATEBASE MONITORING

Wtd. avg. Depr.RateBase in TY1989 (Adopted in GRC)	233
Wtd. avg. Depr.RateBase in TY1989 (use updated est.	233
Wtd. avg. Depr.RateBase in AY1990 (Adopted in GRC)	214
Wtd. avg. Depr.RateBase in AY1990 (use updated est.	214

SAN DIEGO GAS & ELECTRIC COMPANY
Steam Department
REVENUE REQUIREMENTS FOR ATTRITION YEAR 1990
Thousands Of 1990$

ITEM	ATTRITION YEAR 1990	
O & M EXPENSES :		
Labor Escalation	$36	(59)
Non-Labor Escalation	30	(60)
Total O&M Expenses	65	
CAPITAL RELATED ITEMS :		
Book Depreciation Expenses	0	(61)
Ad Valorem Taxes	0	(62)
Accelerated Amortization	0	(63)
State Tax Depreciation	(0)	(64)
Federal Tax Depreciation	(0)	(65)
ITC normalized	0	(66)
Interest Synchronization	0	(67)
Debt cost	(1)	(68)
Preferred Stock cost	(0)	(69)
Common Equity cost	(2)	(70)
Total Capital Related Items	(3)	
OTHER AUTHORIZED ITEMS :		
Retirement of debt (Adopted in AY 1990)	(0)	
Book Depreciation exp. adj. (Adopted in AY1990)	0	
Total Other Authorized Items	(0)	
TOTAL ADD'L REVENUE REQUIREMENTS ---->	$62	

SAN DIEGO GAS & ELECTRIC COMPANY
Steam Department
ATTRITION YEAR 1991

Labor Base

Labor Base for AY 1991 in 1990$ (Adopted in AY1990)	760	
1990 Labor Escalation (estimated in GRC)	4.84%	
1989 Labor Escalation (estimated in AY1990)	4.20%	
1989 Labor Escalation (use recorded)	4.20%	
1990 Labor Escalation (use updated estimate)	4.84%	
1991 Labor Escalation (use updated estimate)	5.04%	
Labor Base for AY 1991 in 1991$	799	
Labor Escalation for AY 1991 in 1991$	38	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.019961	
Increase in Revenue Requirement	39	(71)

Non-Labor Base

Non-Labor Base for AY 1990 in 1990$ (Adopted in AY1	$625	
1990 Non-Labor Escalation (estimated in GRC)	4.87%	
1989 Non-Labor Escalation (estimated in AY1989)	4.72%	
1989 Non-Labor Escalation (use recorded)	4.72%	
1990 Non-Labor Escalation (use updated estimate)	4.87%	
1991 Non-Labor Escalation (use updated estimate)	5.21%	
Non-Labor Base for AY 1991 in 1991$	658	
Non-Labor Escalation for AY 1991 in 1991$	33	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.019961	
Increase in Revenue Requirement	33	(72)

Depreciation Exp. (Juris. Alloc. Factor =	1.0000)	
System avg. Depreciation Rate (Adopted in GRC)	0.7244%	
Increase in Wtd. Avg. Plant in Service for AY1991 (Adopted in GRC)	55	
Increase in Depreciation expense	0	
Increase in Depreciation expense (Calif.)	0	
Net-to-Gross Multiplier (Adopted in GRC)	1.703853	
Increase in Revenue Requirement	1	(73)

Ad Valorem Taxes (Juris. Alloc. Factor =	1.0000)	
System avg. Ad Valorem Tax Rate (Adopted in GRC)	0.1483%	
Increase in AY1991 EOY Plant in Service from TY1990 EOY Plant in Service at wtd-to-net ratio of 0.294 (Adopted in GRC)	53	
Increase in Ad Valorem Taxes	0	
Increase in Ad Valorem Taxes (Calif.)	0	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.019961	
Increase in Revenue Requirement	0	(74)

Accel. Amort. (Juris. Alloc. Factor =	1.0000)	
Attrition Year 1991 (Adopted in GRC)	0	
Attrition Year 1990 (adopted in GRC)	0	
Increase in Accel. Amortization	0	
Increase in Accel. Amortization (Calif.)	0	
Net-to-Gross Multiplier (Adopted in GRC)	1.703853	
Increase in Revenue Requirement	0	(75)

State Tax Depr. (Juris. Alloc. Factor =		1.0000)	
State Tax Depr. Rate (Adopted in GRC)		1.4362%	
Increase in AY1991 EOY Plant in Service from TY1990 EOY Plant in Service at wtd-to-net ratio of 0.294 (Adopted in GRC)		53	
Increase in State Tax Depreciation		1	
Increase in State Tax Depreciation (Calif.)		1	
Increase in CCFT (Tax Rate =	9.3000%	(0)	
Increase in FIT (Tax Rate =	34.0000%	0	
Increase in State & Federal Taxes		(0)	
Net-to-Gross Multiplier (Adopted in GRC)		1.703853	
Increase in Revenue Requirement		(0)	(76)

Federal Tax Depr. (Juris. Alloc. Factor =		1.0000)	
Federal Tax Depr. Rate (Adopted in GRC)		1.2185%	
Increase in AY1991 EOY Plant in Service from TY1990 EOY Plant in Service at wtd-to-net ratio of 0.294 (Adopted in GRC)		53	
Increase in Federal Tax Depreciation		1	
Increase in Federal Tax Depreciation (Calif.)		1	
Increase in Federal Taxes (Tax Rate	34.0000%	(0)	
Net-to-Gross Multiplier (Adopted in GRC)		1.703853	
Increase in Revenue Requirement		(0)	(77)
ITC Normalized (Juris. Alloc. Factor = (Applicable to IRC Sec. 46(f)(2) utilities only.)		1.0000)	
Attrition Year 1991 (Adopted in GRC)		0	
Attrition Year 1990 (adopted in GRC)		0	
Increase in ITC normalized		0	
Increase in ITC normalized (Calif.)		0	
Net-to-Gross Multiplier (Adopted in GRC)		1.703853	
Increase in Revenue Requirement		0	(78)
INTEREST SYNCHRO. (Juris. Alloc. Factor = (Applicable to IRC Sec. 46(f)(2) utilities only.))		1.0000)	
ITC Normalized in AY1991 (from above)		0	
Wtd. cost of Long Term Debt (Adopted in AY1991)		3.74%	
Increase in CCFT interest		0	
Increase in CCFT (Tax Rate =	9.3000%	0	
Increase in FIT (Tax Rate =	34.0000%	0	
Increase in State & Federal Taxes		0	
Increase in State & Federal Taxes (Calif.)		0	
Net-to-Gross Multiplier (Adopted in GRC)		1.703853	
Increase in Revenue Requirement		0	(79)

Rate Base (Juris. Alloc. Factor =	1.0000)
Wtd. avg. Depr Rate Base for AY1990 (Adopted in GRC	214
Plant in Service (Adopted in GRC)	
Wtd. avg. Additions for AY1990	(18)
Net Additions for AY1990	57
Wtd. avg. Additions for AY1991	16
PHFU (Adopted in GRC)	
Wtd. avg. Additions for AY1990	0
Net Additions for AY1990	0
Wtd. avg. Additions for AY1991	0
Depreciation Reserve (Adopted in GRC)	
Wtd. avg. Depreciation Reserve for AY1990	5,205
Wtd. avg. Depreciation Reserve for AY1991	(5,243)
Taxes Deferred - ACRS (Adopted in GRC)	
Wtd. avg. Deferred Taxes - MACRS for AY1990	87
Wtd. avg. Deferred Taxes - MACRS for AY1991	(97)
Taxes Deferred - Amort & Other (Adopted in GRC)	
Wtd. avg. Deferred Taxes - Amort & Other for AY1990	2
Wtd. avg. Deferred Taxes - Amort & Other for AY1991	(2)
Wtd. avg. Depr Rate Base for AY1991	220
Wtd. avg. Depr. Rate Base in Attrition Year 1990	214
Wtd. avg. Depr. Rate Base in Attrition Year 1991	220
Wtd. avg. Depr. Rate Base in AY 1990 (Calif.)	214
Wtd. avg. Depr. Rate Base in AY 1991 (Calif.)	220
Long-term Debt	
Return on Debt in AY 1990 (Adopted in AY1990)	9.24%
Debt capitalization in AY 1990 (Adopted in AY1990)	40.50%
Wtd. cost of Debt for Attrition Year 1990	3.74%
Return on Debt in AY 1991 (Adopted in AY1991)	9.24%
Debt capitalization in AY 1991 (Adopted in AY1991)	40.50%
Wtd. cost of Debt for Attrition Year 1991	3.74%
Increase in Debt cost in Attrition Year 1991	0
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.019961
Increase in Revenue Requirement	0 (80)

Preferred Stock

Return on Pref. Stock in AY 1990 (Adopted in AY1990	7.28%	
Pref.Stk. capitalization AY 1990 (Adopted in AY1990	8.50%	
Wtd. cost of Preferred Stock for Test Year 1990	0.62%	
Return on Pref. Stock in AY 1991 (Adopted in AY1991	7.28%	
Pref.Stk. capitalization AY 1991 (Adopted in AY1991	8.50%	
Wtd. cost of Preferred Stock for Att. Year 1991	0.62%	
Increase in Pref. Stock cost in Att. Year 1991	0	
Net-to-Gross Multiplier (Adopted in GRC)	1.703853	
Increase in Revenue Requirement	0	(81)

Common Equity

Return on Com. Eq. in AY 1990 (Adopted in AY1990)	12.75%	
Com. Eq. capitalization AY 1990 (Adopted in AY1990)	51.00%	
Wtd. cost of Common Equity for Test Year 1990	6.50%	
Return on Com. Eq. in AY 1991 (Adopted in AY1991)	12.75%	
Com. Eq. capitalization AY 1991 (Adopted in AY1991)	51.00%	
Wtd. cost of Common Equity for Att. Year 1991	6.50%	
Increase in Common Equity cost in Att. Year 1991	0	
Net-to-Gross Multiplier (Adopted in GRC)	1.703853	
Increase in Revenue Requirement	1	(82)

Retirement of debt

Increase in Revenue Requirement (Adopted in AY1991)	(0)

RATEBASE TRACKING

Wtd. avg. Depr.Rate Base in TY1989 (Adopted in GRC)	233
Wtd. avg. Depr.Rate Base in TY1989 (estimated at the time of filing for AY 1990)	233
Wtd. avg. Depr.Rate Base in TY1989 (recorded)	233
Wtd. avg. Depr.RateBase in AY1990 (Adopted in GRC)	214
Wtd. avg. Depr.RateBase in AY1990 (estimated at the time of filing for AY 1990)	214
Wtd. avg. Depr.RateBase in AY1990 (use updated est.	214
Wtd. avg. Depr.RateBase in AY1991 (Adopted in GRC)	220
Wtd. avg. Depr.RateBase in AY1991 (use updated est.	220

SAN DIEGO GAS & ELECTRIC COMPANY
Steam Department
REVENUE REQUIREMENTS FOR ATTRITION YEAR 1991
Thousands Of 1991$

ITEM	ATTRITION YEAR 1991	
O & M EXPENSES :		
Labor Escalation	$39	(71)
Non-Labor Escalation	33	(72)
Total O&M Expenses	72	
CAPITAL RELATED ITEMS :		
Book Depreciation Expenses	1	(73)
Ad Valorem Taxes	0	(74)
Accelerated Amortization	0	(75)
State Tax Depreciation	(0)	(76)
Federal Tax Depreciation	(0)	(77)
ITC normalized	0	(78)
Interest Synchronization	0	(79)
Debt cost	0	(80)
Preferred Stock cost	0	(81)
Common Equity cost	1	(82)
Total Capital Related Items	1	
OTHER AUTHORIZED ITEMS :		
Retirement of debt (Adopted in AY 1991)	(0)	
Book Depreciation exp. adj. (Adopted in AY1991)	0	
Total Other Authorized Items	(0)	
TOTAL ADD'L REVENUE REQUIREMENTS ---->	$74	

(END OF APPENDIX B)

SAN DIEGO GAS AND ELECTRIC COMPANY
Electric Department - California Jurisdiction
SUMMARY OF REVENUE CHANGES
Test Year 1989

Revenue Element	Present rate revenues 6/ (000's of $)	Revenue change (000's of $)	Adopted Revenue 6/ (000's of $)	Average Rate 6/ (cents/Kwh)
	(a)	(b)	(c)	(d)
Base Rate Revenues				
Base Rate Revenues	$870,018	($91,381)	$778,637	6.046 1/8/
SONGS 2&3 post-COD disallowance	0	(1,502)	(1,502)	(0.012)2/
SONGS 2&3 pre-COD AFUDC disallowance	0	(1,193)	(1,193)	(0.009)2/
Amortization of overcollection in the CLMAC balancing account	0	(3,487)	(3,487)	(0.027)
Total Base Rate Revenues	870,018	(97,563)	772,455	5.998
Major Additions Adjustment Clause (MAAC)				
SONGS 2&3 pre-COD interim rate	0	0	0	0.000 3/
SONGS 2&3 pre-COD amortization	(19,680)	(6,733)	(26,413)	(0.204)2/4/
SONGS 2&3 post-COD interim rate	14,631	(14,631)	0	0.000 2/5/
SONGS 2&3 post-COD amortization	0	11,523	11,523	0.089 2/7/
Total MAAC	(5,050)	(9,840)	(14,890)	(0.115)
Conservation & Load Mgmt. Programs Adjustment Clause (CALPAC) rate	0	0	0	0.000
Energy Cost Adjustment Clause (ECAC)	361,073	3,567	364,640	2.816 9/
Annual Energy Rate (AER)	32,198	120	32,318	0.250 9/
Electrical Revenue Adjustment Mechanism (ERAM) balancing account rate	(4,379)	(30,500)	(34,879)	(0.269)9/
Subtotal - Revenue from retail sales	$1,253,860	($134,216)	$1,119,645	8.680
Miscellaneous Revenues	17,005	0	17,005	
Non-Jurisdictional Revenues	1,445	0	1,445	
TOTALS FOR ELECTRIC DEPARTMENT	$1,272,310	($134,216)	$1,138,095	8.790

1/ Includes revenue impact of SONGS 2&3 post-COD expenditures before disallowances ordered in D.88-12-033.
2/ See D.88-12-033.
3/ See D.87-12-065.
4/ Amortization of pre-COD MAAC account balance including the effects of disallowed plant expenditures, AFUDC allocation, and interest on income taxes per D.88-12-033.
5/ Termination of SONGS 2&3 post-COD interim rate.
6/ Based on adopted GRC sales (after employee discounts) of 12,947.5 GWh.
7/ Amortization of post-COD MAAC account balance including the effects of disallowed plant expenditures and interest on income taxes per D.88-12-033.
8/ Reflects the rates of return adopted in D.88-12-094.
9/ Adopted revenues from D.88-12-085.

SAN DIEGO GAS AND ELECTRIC COMPANY
SUMMARY OF REVENUE CHANGES
Test Year 1989

GAS DEPARTMENT

	Revenue Element	Present rate revenues 2/ (000's of $)	Revenue change (000's of $)	Adopted Revenue 2/ (000's of $)	Average Rate 2/ (cents/therm)
1		(a)	(b)	(c)	(d)
2	Base Cost Amount				
3	Base Cost Amount	$121,823	$9,639	$131,462	12.451 3/
4	Amortization of overcollection in the				
5	CLMAC balancing account	0	(1,323)	(1,323)	(0.125)
6					
7	Subtotal	$121,823	$8,316	$130,139	12.326
8	Less: Miscellaneous sales	3,152	0	3,152	
9					
10	Subtotal - Revenue from sales	$118,671	$8,316	$126,987	12.027
11	Miscellaneous sales	3,152	0	3,152	
12	Other including fuel offset revenues	323,197	0	323,197	1/
13					
14	TOTALS FOR GAS DEPARTMENT	$445,020	$8,316	$453,336	42.957

1/ Other previously authorized revenues
2/ Based on adopted GRC sales of 1,055,821,000 therms.
3/ Reflects the rates of return adopted in D.88-12-094.

STEAM DEPARTMENT

	Revenue Element	Present rate revenues 2/ (000's of $)	Revenue change (000's of $)	Adopted Revenue 2/ (000's of $)	Average Rate 2/ ($/1000 lbs.)
15		(a)	(b)	(c)	(d)
16	Base Rate Revenues				
17	Present rate Base Rate Revenues	$954	$500	$1,454	25.581 3/
18					
19	Energy Cost Adjustment Clause (ECAC)				
20	and Steam Revenue Adjustment Mechanism				
21	(SRAM) balancing account rate	270	128	398	7.002 1/
22					
23	Subtotal - Revenues from sales	$1,224	$628	$1,852	32.583
24					
25	TOTALS FOR STEAM DEPARTMENT	$1,224	$628	$1,852	32.583

1/ Per Advice Letter #160-H, requesting changes to be eff. 1/1/89.
2/ Based on adopted GRC sales of 56,840,000 lbs.
3/ Reflects the rates of return adopted in D.88-12-094.

(END OF APPENDIX C)

APPENDIX D
PAGE 1

SAN DIEGO GAS AND ELECTRIC COMPANY 1/
ADOPTED EPMC REVENUE ALLOCATION
EFFECTIVE JANUARY 1, 1989

CUSTOMER GROUP	SALES 2/ (GWH)	PRESENT RATE REV 3/ ($000's)	TOTAL MC REVS 4/ ($000's)	FULL EPMC ($000's)	(%) INC.	AVERAGE RATE ($/KWH)
RESIDENTIAL	5,136	550,308	529,309	509,858	(8)	0.099
SM/MED POWER						
GENERAL SERVICE	1,504	171,703	147,596	142,172	(17)	0.095
GS-DEMAND METERED>20 kW	2,029	181,511	166,945	160,810	(11)	0.079
LARGE POWER						
LARGE TOU > 20 kW	3,110	255,679	236,276	227,593	(11)	0.073
VERY LARGE TOU > 500 kW	910	67,723	59,492	57,306	(15)	0.063
AGRICULTURE	183	17,442	14,612	14,095	(19)	0.077
STREETLIGHTING	75	9,493	4,920	7,811	(18)	0.104
TOTAL	12,947	1,253,860	1,159,150	1,119,645	(11)	0.086

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. Facilities charges are $3.072 million for street lights. Optional TOU meter charges are $20,000 for agriculture and $1,000 for residential.
Reflects revenue requirement from Appendix C.

2/ Sales figures reflect general rate case stipulation. Sales have not been adjusted for employee discounts. Adjusted sales are 12,937.3 gWh (5,126.4 gWh residential).

3/ Present rate revenues reflect authorized residential undercollection to coordinate baseline changes in D.88-10-062 with this general rate case. This decision terminates the undercollection, and completes implementation of baseline rate changes ordered in D.88-10-062.

4/ Based on Marginal Costs as modified by this decision.

APPENDIX D
PAGE 2
SAN DIEGO GAS AND ELECTRIC COMPANY 1/
ALLOCABLE REVENUE REQUIREMENT

CUSTOMER GROUP	ADJUSTED SALES /2 (GWH)	REVENUE REQ ($000's)	FACILITIES CHARGES ($000's)	ECAC ($000's)	AER ($000's)	MAAC ($000's)	ERAM ($000's)	BASE ($000's)
RESIDENTIAL	5,126.4	509,858.2	1.0	144,360.2	12,816.1	(5,900.2)	(13,790.1)	372,371.3
SM/MED POWER								
A	1,504.0	142,171.9		42,352.6	3,760.0	(1,731.0)	(4,045.8)	101,836.1
AD	2,029.0	160,809.9		57,136.6	5,072.5	(2,335.2)	(5,458.0)	106,394.0
GROUP TOTAL	3,533.0	302,981.8		99,489.3	8,832.5	(4,066.2)	(9,503.8)	208,230.1
LARGE POWER								
AL-TOU	3,110.0	227,593.0		87,577.6	7,775.0	(3,579.4)	(8,365.9)	144,185.7
A6-TOU	910.0	57,305.7		25,625.6	2,275.0	(1,047.3)	(2,447.9)	32,900.4
GROUP TOTAL	4,020.0	284,898.7		113,203.2	10,050.0	(4,626.8)	(10,813.8)	177,086.1
AGRICULTURE								
PA	175.4	13,517.0		4,939.3	438.5	(201.9)	(471.8)	8,813.0
PA-TOU	7.5	578.0	20.0	211.2	18.8	(8.6)	(20.2)	356.8
GROUP TOTAL	182.9	14,095.0		5,150.5	457.3	(210.5)	(492.0)	9,189.8
STREETLIGHTING	75.0	7,811.2	3,072.0	2,112.0	187.5	(86.3)	(201.8)	2,727.8
TOTAL	12,937.3	1,119,645.0	3,073.0	364,315.1	32,343.3	(14,890.0)	(34,801.4)	769,605.0

1/ Allocable revenue requirement equals revenue requirement from Appendix C less facilities charges.
GRC sales applied to rates for ECAC, AER and ERAM components in A.88-07-003.

2/ Sales adjusted for employee discounts.

APPENDIX D
PAGE 3
SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED MARGINAL COST REVENUE RESPONSIBILITY
TEST YEAR 1989
(MILLIONS OF $)

		DEMAND				
	ENERGY	GENERATION	TRANSMIS.	DISTRIBUTION	CUSTOMER	TOTAL
Residential	165.8	72.5	29.3	175.8	90.2	533.6
General service	48.8	27.8	9.7	49.3	13.9	149.6
GS-Demand Meter >20	66.0	33.9	11.3	53.2	4.4	168.8
TOU over 20 mW	99.4	48.4	15.5	67.7	8.0	239.0
TOU over 500 mW	28.7	11.9	3.8	15.5	0.3	60.1
Agriculture	5.7	2.1	0.8	4.2	2.1	14.8
Street Lighting	2.3	0.5	0.2	1.4	0.5	5.0
TOTAL	416.7	197.0	70.6	367.1	119.3	1170.7

(END OF APPENDIX D)

APPENDIX D

PAGE 4

SAN DIEGO GAS AND ELECTRIC COMPANY

DEMAND DETERMINANTS

TEST YEAR 1989 1/ 2/ 3/

	COINCIDENT (MW)	NON-COIN (MW)	% OF SERVICE AT VOLTAGE LEVEL 4/ TRANSMIS.	PRIMARY	SECONDARY
Residential	872	2143	0%	0%	100%
General service	335	569	0%	0%	100%
GS-Demand Meter >20 kW	408	598	0%	2%	98%
TOU over 20 kW	585	742	0%	13%	87%
TOU over 500 kW	147	185	6%	94%	0%
Agriculture	25	50	0%	0%	100%
Street Lighting	5	18	0%	5%	95%
TOTAL	2377	4305			

1/ Customer class generation demand equals class coincident demand.

2/ Customer class transmission demand equals 76% of coincident demand plus 24% of non-coincident demand.

3/ Customer class distribution demand equals 26% of coincident demand plus 74% of non-coincident demand.

4/ Voltage loss factors equal on-peak energy line loss factors shown in Appendix E. To obtain correct marginal demand cost revenues, marginal demands are multiplied by marginal demand costs and voltage losses.

(END APPENDIX D)

APPENDIX E
PAGE 2

SAN DIEGO GAS AND ELECTRIC COMPANY
DEVELOPMENT OF ADOPTED MARGINAL DEMAND-RELATED GENERATION COSTS
Test Year 1989

		1989$/KW/YEAR
(1)	COMBUSTION TURBINE INVESTMENT	$519.00
(2)	General Plant Loading (L1 * 1.70%)	8.82
(3)	Working Capital Loading ((L1 + L2) * 1.45%)	7.65
(4)	Subtotal (L1 through L3)	535.48
(5)	ANNUALIZED COST (L4 * 10.65%)	57.03
(6)	Administrative and General Loading ((L1 + L2) * 0.2544%)	1.34
(7)	Annual Fuel Inventory	0.56
(8)	Operation & Maintenance Loading	5.43
(9)	TOTAL ANNUAL MARGINAL DEMAND-RELATED GENERATION COSTS	
	(a) Unadjusted for Revenue Taxes (L5 through L8)	64.36
	(b) Adjusted for Revenue Taxes (L 9a * 1.00929)	64.96
	(c) Adjusted for 15% Reserve Margin (L 9b * 1.15)	74.70

APPENDIX E
PAGE 3

SAN DIEGO GAS AND ELECTRIC COMPANY
DEVELOPMENT OF ADOPTED MARGINAL DEMAND-RELATED TRANSMISSION COSTS
Test Year 1989

		1989$/KW/YEAR
(1)	TRANSMISSION INVESTMENT	$171.39
(2)	General Plant Loading (L1 * 1.70%)	2.91
(3)	Working Capital Loading ((L1 + L2) * 1.45%)	2.53
(4)	Subtotal (L1 through L3)	176.83
(5)	ANNUALIZED COST (L4 * 9.91%)	17.52
(6)	Administrative and General Loading ((L1 + L2) * 0.2544%)	0.44
(7)	Operation & Maintenance Loading (O&M -- $3.05 + 37.6% A&G Adder)	4.20
(8)	TOTAL ANNUAL MARGINAL DEMAND-RELATED TRANSMISSION COSTS	
	(a) Unadjusted for Revenue Taxes (L5 through L7)	22.16
	(b) Adjusted for Revenue Taxes (L 8a * 1.00929)	22.37

APPENDIX E
PAGE 4

SAN DIEGO GAS AND ELECTRIC COMPANY
DEVELOPMENT OF ADOPTED MARGINAL DEMAND-RELATED DISTRIBUTION COSTS
Test Year 1989

		1989$/KW/
(1)	DISTRIBUTION INVESTMENT	$682.71
(2)	General Plant Loading (L1 * 1.70%)	11.61
(3)	Working Capital Loading ((L1 + L2) * 1.45%)	10.07
(4)	Subtotal (L1 through L3)	704.38
(5)	ANNUALIZED COST (L4 * 10.11%)	71.21
(6)	Administrative and General Loading ((L1 + L2) * 0.2544%)	1.77
(7)	Operation & Maintenance Loading (O&M dollars of $9.67 plus 37.6% A&G adder)	13.31
(8)	TOTAL ANNUAL MARGINAL DEMAND-RELATED TRANSMISSION COSTS	
	(a) Unadjusted for Revenue Taxes (L5 through L7)	86.29
	(b) Adjusted for Revenue Taxes (L 8a * 1.00929)	87.09

APPENDIX E
PAGE 5

SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED MARGINAL ENERGY COSTS
Test Year 1989

MARGINAL ENERGY COSTS	Summer			Winter			Annual Average
	On-Peak	Mid-Peak	Off-Peak	On-Peak	Mid-Peak	Off-Peak	
Fuel Price ($/MBTU)	1.954	1.954	1.954	1.954	1.954	1.954	1.954
Generation Marginal Energy Cost (c/kWh) (Includes variable O&M (c/kWh))	3.0960	2.9432	2.6170	3.2230	3.1001	2.7090	2.8637
X Revenue Related Tax Factor (Wt Avg Franchise Fee, inc. City SD)	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093	1.0093
GENERATION MARGINAL ENERGY COST (c/kWh) (Includes variable O&M (c/kWh) & Adj. for Revenue Related Tax Factor)	3.1248	2.9705	2.6413	3.2529	3.1289	2.7342	2.8903
Transmission							
Energy Loss Factor	1.0306	1.0270	1.0190	1.0306	1.0268	1.0189	1.0232
MARGINAL ENERGY COST + LOSSES (c/kWh) (Includes variable O&M (c/kWh))	3.2204	3.0507	2.6915	3.3525	3.2128	2.7858	2.9574
Primary Level							
Energy Loss Factor	1.0415	1.0366	1.0258	1.0416	1.0362	1.0256	1.0315
MARGINAL ENERGY COST + LOSSES (c/kWh) (Includes variable O&M (c/kWh))	3.3540	3.1624	2.7609	3.4919	3.3291	2.8572	3.0505
Secondary Level							
Energy Loss Factor	1.0263	1.0232	1.0163	1.0263	1.0230	1.0163	1.0200
MARGINAL ENERGY COST + LOSSES (c/kWh) (Includes variable O&M (c/kWh))	3.4422	3.2358	2.8059	3.5838	3.4056	2.9037	3.1115

(END OF APPENDIX E)

APPENDIX F

SAN DIEGO GAS AND ELECTRIC COMPANY

ELECTRIC RATE DESIGN APPENDIX

NOTE: This rate appendix does not include PUC surcharge of $.00012/kWh. SDG&E assesses the surcharge separately, in accordance with its tariffs.

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PAGE 1
SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED RESIDENTIAL RATES

EFFECTIVE 01-01-89
($/KWH)

SCHEDULE	DR	DA-TOU	DU-TOU
MINIMUM BASE RATE CHARGE ($/DAY)	$0.164	$0.224	$0.224
a/			
BASELINE	$0.08148	--	--
NON-BASELINE	$0.12609	--	--
ON-PEAK ENERGY RATE			
BASELINE	--	$0.12716	$0.08785
NON-BASELINE	--	$0.19769	$0.13595
OFF-PEAK ENERGY RATE			
BASELINE	--	$0.06358	$0.04392
NON-BASELINE	--	$0.09839	$0.06797
METER CHARGE ($/DAY)	--	$0.06	$0.06

a/ The baseline energy rate is 94.2% of the System Average Rate (SAR), where the SAR is total revenue requirement from sales divided by total sales ($1,119.645 MM / 12,947 MMKWH = 0.08648 $/KWH). Baseline rate was set by D.88-10-062.

RESIDENTIAL SCHEDULES WITH REVISED DISCOUNTS:

DS $.11 per apartment per day
DT $.312 per mobile home unit per day

APPENDIX F
PAGE 2
SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED RESIDENTIAL RATES

EFFECTIVE 01-01-89
($/KWH)

SCHEDULE	DSMF	DR-TOU	
SEASON	ANNUAL	SUMMER	WINTER
CUSTOMER CHARGE ($/MONTH)	$20.00	--	--
MINIMUM BASE RATE CHARGE ($/DAY)	--	$0.16	$0.16
ON-PEAK DEMAND CHARGE ($/KW)	$8.15	--	--
BASELINE	$0.07215	--	--
NON-BASELINE	$0.11413	--	--
ON-PEAK ENERGY RATE	--	$0.35038	$0.11012
OFF-PEAK ENERGY RATE	--	$0.10220	$0.10220
DR-TOU BASELINE CREDIT a/	--	$0.04750	$0.04750
METER CHARGE ($/MONTH)	--	$3.28	$3.28

a/ DR-TOU 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 F

Page 3

SAN DIEGO GAS AND ELECTRIC COMPANY

ADOPTED ELECTRIC BASELINE ALLOWANCES, EXCEPT DM

			---------- Phase-In Schedule ----------			
Category	Season	Zone	Year	Adopted	Change	% AAC
All-Elect.	Summer	1	89	325	-25	63
			90	300	-25	60
		3	89	600	-50	59
	Winter	1	89	600	-50	75
			90	550	-50	73
			91	500	-50	70
		3	89	700	-50	72
			90	650	-50	69

Schedule DM

			---------- Phase-In Schedule ----------			
Category	Season	Zone	Year	Adopted	Change	% AAC
Basic	Summer	1	89	173	-15	62
			90	160	-13	59
			91	150	-10	56
		3	89	425	125	51
	Winter	1	89	175	-13	59
All-Elect.	Summer	1	89	290	-48	71
			90	255	-35	65
			91	225	-30	58
		2	89	353	-20	61
			90	340	-15	59
			91	325	-15	57
	Winter	1	89	480	-83	83
			90	410	-70	76
			91	350	-60	68
		2	89	595	-43	74
			90	555	-40	72
			91	525	-30	69
		3	89	520	-43	73
			90	485	-35	71
			91	450	-35	67

APPENDIX F
PAGE 4
SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED SMALL AND MEDIUM POWER RATES

EFFECTIVE 01-01-89
($/KWH)

SCHEDULE	A	AD
CUSTOMER CHARGE	$5/MONTH	$10/MONTH
DEMAND CHARGE ($/KW/MONTH)	--	$5.50
FLAT ENERGY RATE	$0.09029	$0.06071

SCHEDULE CHANGES:
(1) A and AD customers may take service under AL-TOU. Applicability restrictions deleted.
(2) AD customers may take standby service. The on-peak summer and winter rates for such customers is limited to $.67 and $.26 per kwh respectively.

APPENDIX F
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SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED LARGE POWER RATES

EFFECTIVE 01-01-89
($/KWH)

SCHEDULE	AL-TOU			A6-TOU	
VOLTAGE	SECONDARY	PRIMARY	TRANSMIS	PRIMARY	TRANSMIS
CUSTOMER CHARGE ($/MONTH)	$20.00	$20.00	$20.00	$600.00	$600.00
PEAK DEMAND CHARGE ($/KW/MONTH)					
SUMMER	$14.42	$14.42	$9.07	$17.18	$11.01
WINTER	$3.36	$3.36	$1.34	$4.01	$1.79
NON-TIME RELATED DEMAND CHARGE ($/KW/MONTH)	$3.05	$2.42	$1.02	$2.42	$1.02
SUMMER ENERGY CHARGE:					
ON-PEAK	$0.07578	$0.07090	$0.06877	$0.07090	$0.06877
MID-PEAK	$0.04900	$0.04667	$0.04527	$0.04667	$0.04527
OFF-PEAK	$0.03706	$0.03468	$0.03364	$0.03468	$0.03364
WINTER ENERGY CHARGE:					
ON-PEAK	$0.06795	$0.06355	$0.06164	$0.06355	$0.06164
SEMI-PEAK	$0.04286	$0.03979	$0.03859	$0.03979	$0.03859
OFF-PEAK	$0.03605	$0.03281	$0.03182	$0.03281	$0.03182
RATE LIMITER:					
AVERAGE	$0.16	$0.16	$0.16	$0.16	$0.16

SCHEDULE CHANGES:
(1) Applicability of AL-TOU is expanded to include customers qualifying for service under schedule A or AD.
(2) Optional time period and rates added to AL-TOU and A6-TOU. See following page for details.

SPECIAL CONDITION CHANGES (AL-TOU and A6-TOU):
The utility may limit the number of customers electing the optional time period to ten a year. Customers electing the optional time period are prohibited from switching to the regular time period for 12 months.

INTERRUPTIBLE CREDITS

	DEMAND CHARGE CREDIT ($/KW/MONTH)
I-1: OPTION A	$3.27
OPTION B	$2.18
OPTION C	
UTILITY CONTROLLED	$3.27
OTHER INTERRUPTIBLE DEMAND	$2.18

	ONE-YEAR CREDIT ($/KW/MONTH)	FIVE-YEAR CREDIT ($/KW/MONTH)
I-2: OPTION A	$5.33	$6.72
OPTION B	$4.90	$6.16
OPTION C	$3.95	$4.99
OPTION D	$3.62	$4.57

NOTE: All I-2 customers receive $.27 credit per interruption per kW.

APPENDIX F
PAGE 6
SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED LARGE POWER RATES

EFFECTIVE 01-01-89
($/KWH)

SCHEDULE	AL-TOU (OPTIONAL TIME PERIOD)			A6-TOU (OPTIONAL TIME PERIOD)	
VOLTAGE	SECONDARY	PRIMARY	TRANSMIS	PRIMARY	TRANSMIS
CUSTOMER CHARGE ($/MONTH)	$20.00	$20.00	$20.00	$600.00	$600.00
PEAK DEMAND CHARGE ($/KW/MONTH)					
SUMMER	$16.19	$16.19	$10.19	$19.29	$12.37
WINTER	$3.36	$3.36	$1.34	$4.01	$1.79
NON-TIME RELATED DEMAND CHARGE ($/KW/MONTH)	$3.05	$2.42	$1.02	$2.42	$1.02
SUMMER ENERGY CHARGE:					
ON-PEAK	$0.08510	$0.07963	$0.07724	$0.07963	$0.07724
MID-PEAK	$0.05503	$0.05241	$0.05084	$0.05241	$0.05084
OFF-PEAK	$0.03706	$0.03468	$0.03364	$0.03468	$0.03364
WINTER ENERGY CHARGE:					
ON-PEAK	$0.06795	$0.06355	$0.06164	$0.06355	$0.06164
SEMI-PEAK	$0.04286	$0.03979	$0.03859	$0.03979	$0.03859
OFF-PEAK	$0.03605	$0.03281	$0.03182	$0.03281	$0.03182
RATE LIMITER:					
AVERAGE	$0.16	$0.16	$0.16	$0.16	$0.16

SCHEDULE CHANGES:
Optional summer time period is:

Dates	May 1-September 30
On-peak	12 P.M. - 6 P.M Weekdays
Semi-peak	6 A.M. - 12 P.M. Weekdays
	6 P.M. - 10 P.M. Weekdays
Off-peak	10 P.M. - 6 A.M. Weekdays plus weekends and holidays

SPECIAL CONDITION ADDITIONS APPLICABLE TO OPTIONAL TIME PERIOD CUSTOMERS:
(1) The utility may limit the number of customers electing the optional time period to ten a year. Service will be provided in the order requests are received.
(2) Customers electing the optional time period are prohibited from switching to the regular time period for 12 months.

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PAGE 7
SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED LARGE POWER RATES

EFFECTIVE 01-01-89
($/KWH)

SCHEDULE	AO-TOU	A06-TOU
CUSTOMER CHARGE	$50/MONTH	$250/MONTH
PEAK DEMAND CHARGE ($/KW/MONTH):		
SUMMER	$13.00	$15.49
WINTER	$3.50	$4.17
NON-TIME RELATED DEMAND CHARGE ($/KW/MONTH)	$7.31	$7.31
ON-PEAK ENERGY RATE	$0.04275	$0.04275
SEMI-PEAK ENERGY RATE	$0.03577	$0.03577
OFF-PEAK ENERGY RATE	$0.03196	$0.03196

APPENDIX F
PAGE 8
SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED STANDY RATES

EFFECTIVE 01-01-89
($/KWH)

SCHEDULE	S		
VOLTAGE	SECONDARY	PRIMARY	TRANSMISSION
CONTRACT DEMAND CHARGE ($/KW/MONTH)	$2.44	$1.94	$0.82
RATE LIMITER:			
SUMMER ON-PEAK	$0.67	$0.67	$0.67
WINTER ON-PEAK	$0.26	$0.26	$0.26

SCHEDULE CHANGE: AD customers are eligible to receive standby service.

Special condition change: Customers electing to receive standby service are restricted to a single rate schedule.

APPENDIX F
PAGE 9
SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED AGRICULTURAL RATES

RATE SCHEDULE	CUSTOMER CHARGE ($/MONTH)	METER CHARGE ($/MONTH)	DEMAND CHARGE ON-PEAK ($/KW)	DEMAND CHARGE SEMI-PEAK ($/KW)	ENERGY CHARGE ($/KWH) FLAT		
PA	$8.00	--	--	--	0.07478		
					ON-PEAK	SEMI-PEAK	OFF-PEAK
PA-TOU	$8.00	$10.00	--	--	0.13293	--	0.06073
PA-T-1	$20.00	--			0.08063	0.05926	0.03802
OPTION A			$9.50 /a	$0.50			
OPTION B			$8.34	$0.50			
OPTION C			$8.16	$0.50			
OPTION D			$8.50	$0.50			
OPTION E			$8.33	$0.50			
OPTION F			$7.97	$0.50			

a/ On-peak demand charge is applied to contribution to monthly peak.

SPECIAL CONDITION CHANGES:

(1) Expiration date removed from Schedule PA-TOU.

(2) Expiration date removed from Schedule PA-T-1.

APPENDIX F
PAGE 10
SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED EXPERIMENTAL RATES

EFFECTIVE 01-01-89
($/KWH)

SCHEDULE	AE-1	R-TOU-1	R-TOU-2	AE-2	R-TOU-3	R-TOU-4
	(closed)	(closed)	(closed)	(new)	(new)	(new)
CUSTOMER CHARGE	$600.00	$600.00	$600.00			
MAXIMUM DEMAND CHARGE ($/KW/MONTH)						
SECONDARY	--	--	--			
PRIMARY	--	--	--			
TRANSMISSION	--	--	--			
MINIMUM CONTRACT DEMAND ($/KW/MONTH)	$13.75	$13.75	$13.75			
SEMI-PEAK DEMAND CHARGE ($/KW/MONTH)	$0.50	$0.50	$0.50			
ENERGY CHARGE:						
SUPER-PEAK	--	$0.94458	$0.49458			
ON-PEAK	$8.29114	$0.29627	$0.13537			
MID-PEAK	$0.04770	$0.04202	$0.02941			
OFF-PEAK	$0.03066	$0.03066	$0.03066			

SCHEDULES AE-1, R-TOU-1 AND R-TOU-2 ARE CLOSED TO NEW CUSTOMERS BY THIS DECISION.

SCHEDULE CHANGES TO PG-QF:
Closed to new customers with generation facilities above 20 kW on July 1, 1989.
Special condition changes:
Conditions related to energy netting to be eliminated for all customers upon termination of the cogeneration project or June 30, 1999, whichever comes first.

SCHEDULE CHANGES TO PG:
Closed to new customers on June 30, 1989.
Special condition change:
Conditions related to energy netting to be eliminated for all customers on June 30, 1989.

ADDITION TO RULE 9--BILLING (BECOMES EFFECTIVE NO EARLIER THAN MARCH 1, 1989).

A monthly late payment charge, equal to SDG&E's authorized return on rate base divided by 12 and rounded to the nearest one-tenth of one percent, may be assessed on non-domestic accounts with billing in arrears if not received at the office of the utility, or by a duly authorized agent of the utility, by the "late charge date" as shown on the bill. The "late charge date" will be at least 25 days from the date mailed. Payments applied shall satisfy the oldest portion of the bill first, any other billings second, and the current billing last. The charge may then be applied to any remaining unpaid balance.

The monthly late payment charge for state agencies shall be the lowest of the following: 1.2 percent; 1 percent above the Pooled Money Investment Account rate divided by 12 and rounded to the nearest one-tenth of one percent; or SDG&E's authorized return on rate base divided by 12 and rounded to the nearest one-tenth of one percent.

SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED STREET LIGHTING RATES
Effective 1/1/89

Rate Schedule Watts	Lumens	Rate ($/Lamp)
LS-1, Mercury Vapor, Class A		
175	7,000	$9.57
250	10,000	$12.65
400	20,000	$17.22
700	35,000	$32.53
LS-1, Mercury Vapor, Class C, 1-Lamp		
175	7,000	$18.05
250	10,000	$23.94
400	20,000	$28.51
LS-1, Mercury Vapor, Class C, 2-Lamp		
175	7,000	$27.36
400	20,000	$46.32
LS-1, HPSV, Class A		
70	5,800	$6.29
100	9,500	$7.25
150	16,000	$8.55
200	22,000	$10.26
250	30,000	$12.94
400	50,000	$16.05
1,000	140,000	$33.27
LS-1, HPSV, Class B, 1-Lamp		
70	5,800	$6.96
100	9,500	$7.92
150	16,000	$9.22
200	22,000	$11.13
250	30,000	$13.81
400	50,000	$17.01
1,000	140,000	$34.30
LS-1, HPSV, Class B, 2-Lamp		
70	5,800	$12.08
100	9,500	$13.99
150	16,000	$16.60
200	22,000	$20.28
250	30,000	$25.64
400	50,000	$31.78
1,000	140,000	$66.33
LS-1, HPSV, Class C, 1-Lamp		
70	5,800	$14.77
100	9,500	$15.73
150	16,000	$17.05

SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED STREET LIGHTING RATES
Effective 1/1/89

Rate Schedule Watts	Lumens	Rate ($/Lamp)
200	22,000	$21.55
250	30,000	$24.23
400	50,000	$28.77
1,000	140,000	$46.94
LS-1, HPSV, Class C, 2-Lamp		
70	5,800	$20.80
100	9,500	$22.71
150	16,000	$25.33
200	22,000	$32.38
250	30,000	$37.74
400	50,000	$42.90
1,000	140,000	$78.74
LS-1, LPSV, Class A		
35	4,800	$7.77
55	8,000	$8.37
90	13,500	$10.28
135	22,500	$12.66
180	33,000	$13.74
LS-1, LPSV, Class B, 1-Lamp		
35	4,800	$8.45
55	8,000	$9.16
90	13,500	$11.07
135	22,500	$13.64
180	33,000	$14.72
LS-1, LPSV, Class B, 2-Lamp		
35	4,800	$15.05
55	8,000	$16.37
90	13,500	$20.19
135	22,500	$25.20
180	33,000	$27.36
LS-1, LPSV, Class C, 1-Lamp		
35	4,800	$16.25
55	8,000	$16.97
90	13,500	$18.90
135	22,500	$24.06
180	33,000	$25.14
LS-1, LPSV, Class C, 2-Lamp		
35	4,800	$23.76
55	8,000	$25.08
90	13,500	$28.92

SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED STREET LIGHTING RATES
Effective 1/1/89

Rate Schedule Watts	Lumens	Rate ($/Lamp)
135	22,500	$37.30
180	33,000	$39.46
LS-1, Facilities and Rates, Class A		
Center Suspension		$4.69
Non-Standard Wood Pole		
30-foot		$2.35
35-foot		$2.64
Recator Ballast Discount		
175		($0.96)
250		($0.38)
LS-1, Facilities and Rates, Class B & C		
Other app. inst.		$0.00
LS-2, Mercury Vapor, Rate A		
175	7,000	$4.88
250	10,000	$6.78
400	20,000	$10.68
700	35,000	$18.12
1,000	55,000	$25.60
LS-2, Mercury Vapor, Rate B, Energy & Limt Mntce		
175	7,000	$5.47
250	10,000	$7.37
400	20,000	$10.65
LS-2, Mercury Vapor, Surcharge for series service		
175	7,000	$0.39
250	10,000	$0.49
400	20,000	$0.71
700	35,000	$1.29
LS-2, HPSV, Rate A		
50	3,300	$1.35
70	5,800	$2.35
100	9,500	$3.27
150	16,000	$4.48
200	22,000	$5.71
250	30,000	$7.27
310	37,000	$8.90
400	50,000	$11.06
1,000	140,000	$25.60
LS-2, HPSV, Rate B, Energy & Limited Maintenance		

SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED STREET LIGHTING RATES
Effective 1/1/89

Rate Schedule Watts	Lumens	Rate ($/Lamp)
50	3,300	$2.02
70	5,800	$3.01
100	9,500	$3.93
150	16,000	$5.16
200	22,000	$6.39
250	30,000	$7.95
310	37,000	$9.58
400	50,000	$11.74
1,000	140,000	$26.44
LS-2, HPSV, Reduction for 120-volt Reactor Ballast		
70	5,800	($0.39)
100	9,500	($0.52)
150	16,000	($0.48)
LS-2, HPSV, Surcharge for Series Service		
50	3,300	$0.44
70	5,800	($0.21)
100	9,500	($0.22)
150	16,000	$0.02
200	22,000	$0.47
LS-2, LPSV, Rate A		
35	4,800	$1.51
55	8,000	$1.98
90	13,500	$3.27
135	22,500	$4.65
180	33,000	$5.30
LS-2, LPSV, Surcharge for series service		
35	4,800	($0.22)
55	8,000	($0.13)
90	13,500	$0.44
135	22,500	$0.78
180	33,000	$0.50
LS-2, Incandescent Lamps, Rate A, Energy Only		
	1,000	$1.65
	2,500	$3.65
	4,000	$5.52
	6,000	$8.11
	10,000	$13.71
LS-2, Incdsnt Lamps, Rate B, Energy and Lmtd Mntce		
	4,000	$7.42
	6,000	$10.03

SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED STREET LIGHTING RATES
Effective 1/1/89

Rate Schedule Watts	Lumens	Rate ($/Lamp)
OL-1, Mercury Vapor, Rate A, St Light Luminaire		
175	7,000	$9.86
400	20,000	$19.05
OL-1, HPSV, Rate A, Street Light Luminaire		
100	9,500	$8.03
150	16,000	$9.84
250	30,000	$14.82
400	50,000	$17.07
1,000	140,000	$34.86
OL-1, HPSV, Rate B, Directional Luminaire		
250	30,000	$17.38
400	50,000	$21.42
1,000	140,000	$37.87
OL-1, LPSV, Rate A, Street Light Luminaire		
55	8,000	$8.47
90	13,500	$10.41
135	22,500	$12.82
180	33,000	$13.91
OL-1, Pole		
30 ft wood pole		$3.10
35 ft wood pole		$3.48
DWL, facilities Charges		
$ of Util invst.		$0.0228
DWL, Energy and Lamp Maintenance Charge		
50 Watt HPSV		$3.08
100 Watt HPSV		$0.00
100 Watt M. Vapor		$0.00
DWL, Min. Charge		$148.58
LS-3		
Energy Charge		$0.07614
Minimum Charge		$5.81

(END OF APPENDIX F)

APPENDIX G
PAGE 1
SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED PHASE-IN SCHEDULE FOR
RESIDENTIAL GAS BASELINE ALLOWANCES
AND REVISED DISCOUNTS FOR
SCHEDULES GS AND GT

GAS BASELINE ALLOWANCES

	Summer Baseline (at 60%) (Therm/mo)				Winter Baseline (at 70%) (Therm/mo)			
Schedule	Current	1989	1990	1991	Current	1989	1990	1991
GR	20	19.00	18.00	17.00	55.00	51.00	47.00	43.00
GM	15	13.30	12.60	11.90	38.50	35.70	32.90	30.10
GS	20	19.00	18.00	17.00	55.00	51.00	47.00	43.00
GT	20	19.00	18.00	17.00	55.00	51.00	47.00	43.00

RESIDENTIAL SCHEDULES WITH
REVISED DISCOUNTS:

GS - $.062 per apartment per day

GT - $0.197 per mobilehome unit per day

APPENDIX G
PAGE 2

SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED GAS REVENUE ALLOCATION 1/ 2/
Test Year 1989

			REVENUE AT PRESENT RATES		REVENUE AT ADOPTED RATES		REVENUE CHANGES TO BE REFLECTED IN RATES		
	CUSTOMER CLASS	SALES 3/ (M THERMS)	BASE ($000's)	TOTAL ($000's)	BASE ($000's)	TOTAL ($000's)	Amt ($ Thousands) BASE	TOTAL	% INC TOTAL
1	CORE: 1/	423641	98296	240678	98296	240678	0	0	0
	NONCORE: 2/								
	o RETAIL								
	Transmission:								
2	- Cogen	95500	2662	10948	2846	11132	184	184	1.68%
3	- Other	32563	3660	7096	3968	7404	308	308	4.34%
4	WACOG	128063	0	25788	0	25788	0	0	0.00%
	o UTILITY ELECTRIC GENERATION								
5	Transmiss	504117	14051	57793	15015	58757	964	964	1.67%
6	WACOG	504117	0	99563	0	99563	0	0	0.00%
7	NONCORE TOTAL		20373	201188	21828	202643	1455	1455	0.72%

1/ CORE REVENUE ALLOCATION. There is no change in core (residential and commercial) rates. The margin change allocable to core customers is to be reflected in core balancing account to be addressed in SDG&E's next ACAP. The adopted increase in authorized margin (Base Cost Amount) is $11.690 million. See Appendix A for detail. The core/noncore split is 82.5% to core and 17.5% to noncore, as reflected in SDG&E's May 1, 1988 compliance filing. Based on these allocation factors, core and noncore customer's authorized increase in margins are:

	(Thousands of Dollars)		(Thousands of Dollars)
CORE:	9644.25	NONCORE:	2045.75

2/ NONCORE REVENUE ALLOCATION assumes allocation factors used in SDG&E's May 1, 1988 compliance filing for initial allocation. Cogeneration and UEG rates are then equalized as required by D. 87-12-039, resulting in final revenue allocation to these classes. (Noncore's May 1 allocation share is 17.5%: UEG, 8%; cogeneration, 5.8%; other, 3.7%).

[Noncore change in margin of $2.046 million includes $1.455 million change in rates over present rates (assuming GRC stipulated sales), and remaining $591 thousand revenue change (2046-1455) due to increased sales in test year.]

3/ Adopted general rate case sales are 1,055,821,000 therms.

SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED NONCORE GAS RATES
EFFECTIVE 01-01-89

SCHEDULE

UEG/INTERDEPT
SCHEDULE GTUEG

(Thousands of Dollars)

Monthly Demand Charges:	Jan	2830	July	4555
	Feb	2430	Aug	4674
	Mar	2547	Sept	3966
	April	2451	Oct	3624
	May	3814	Nov	3281
	June	3768	Dec	2573

	(Cents/Therm)
Volumetric Charges: Tier I	6.161
Tier II	3.043

COGENERATION
SCHEDULE GTCG

Customer Charge	No Change
	(Cents/Therm)
Volumetric Demand Charge	11.396 1/

OTHER NONCORE TRANSMISSION
SCHEDULE GTNC

Customer Charge — No Change

Default Rates:	(Cents/Therm)
Average Demand Charge (D-1)	6.890
Seasonal Peak Demand Charge (D-2):	
Summer	4.170
Winter	7.330
Volumetric Charge	7.295

1/ Actual volumetric demand charge for cogenerators varies monthly based on recorded UEG data based on D. 87-12-039.

(END OF APPENDIX G)

APPENDIX H

SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED STEAM REVENUE ALLOCATION AND RATE DESIGN
Test Year 1989

REVENUE ALLOCATION

SCHEDULE	SALES 1/ (1000 LB) & CUST NO	PRESENT RATE REVENUES ($000's)	ADOPTED RATE REVENUES ($000's)
SCHEDULE 1			
Service ($/MO)	285	4	9
Commodity ($/1000 LB)	50214	1076	1626
Subtotal		1080	1635
SCHEDULE 2			
Service ($/MO)	12	0 2/	0
Commodity ($/1000 LB)	6626	143	217
Subtotal		144	217
TOTAL		1224	1852

1/ GRC stipulated sales.
2/ Zero only when rounded.

RATE DESIGN

SCHEDULE	SALES (1000 LB) & CUST NO	PRESENT RATES ($)	ADOPTED RATES ($)
SCHEDULE 1			
Service ($/MO)	285	15	30.00
Commodity ($/1000 LB)	50214	21.428	32.388
SCHEDULE 2			
Service ($/MO)	12	15.15	30.30
Commodity ($/1000 LB)	6626	21.642	32.712

(END OF APPENDIX H)

APPENDIX I
Page 1

LIST OF ACRONYMS

A.	- Application
ACAP	- Annual Cost Adjustment Proceeding
AER	- Annual Energy Rate
AFUDC	- Allowance For Funds Used During Construction
ALJ	- Administrative Law Judge
CALPAC	- Conservation and Load Management Programs - Adjustment Clause
CAL-SLA	- California City - County Street Light Association
CLMAC	- Conservation Load Management Adjustment Clause
COD	- Commercial Operating Date
CPIL	- Center For Public Interest Law
D.	- Decision
DRA	- Division of Ratepayer Advocates
ECAC	- Electric Cost Adjustment Clause
Edison	- Southern California Edison Company
EPMC	- Equal Percent of Marginal Cost
EPRI	- Electric Power Research Institute
ERAM	- Electric Revenue Adjustment Mechanism
FEA	- Federal Executive Agencies
FERC	- Federal Energy Regulatory Commission
FCC	- Federal Communications Commission

APPENDIX I
Page 2

LIST OF ACRONYMS

GRC	- General Rate Case
General Services	- Department of General Services of the - State of California
I.	- Order Instituting Investigation
IPC	- Independent Power Corporation
kW	- Kilowatt
kWh	- Kilowatt hour
KVAR	- Kilovars
LOLP	- Loss of Load Probability
MAAC	- Major Additions Adjustment Clause
MW	- megawatt
NRC	- Nuclear Regulatory Commission
PG&E	- Pacific Gas and Electric Company
Poway	- Poway Unified School District
PU	- State of California Public Utilities Code
Public Advocates	- Americial G.I. Forum, League of Unified Latin - American Citizens, and Filipino American - Political Association
QAU	- Quantifying Added Uncertainty
R.	- Order Instituting Rulemaking
SAPC	- System Average Percent Change
SB	- Senate Bill
SCC	- Small Cogenerators of California

APPENDIX I
Page 3

LIST OF ACRONYMS

SDG&E	- San Diego Gas & Electric Company
SONGS	- San Onofre Nuclear Generating Station
SRAM	- Steam Revneue Adjustment Mechanism
TOU	- Time-of-Use
TSM	- Transformers, Services, and Meters
U-4	- DRA Standard Practice U-4: Determination of - Straight-Line Remaining Life Accruals
UCAN	- Utility Consumers Action Network
W/MBE	- Women/Minority Business Enterprises

(END OF APPENDIX I)

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INDEX

INTERIM OPINION

Summary of Decision

This decision orders San Diego Gas & Electric Company (SDG&E) to reduce electric rates by $89.3 million or 7.0% and authorizes SDG&E to increase gas rates for non-core customers by $1.6 million or 0.8% and steam rates by $0.5 million or 40.9%.

Additionally, revenue requirement changes from the Application (A.) 87-07-044, San Onofre Nuclear Generating Station Units 2 & 3 (SONGS) pre-commercial operating date (COD) amortization and post-COD interim rate, and A.88-07-003, SDG&E's 1988 energy cost adjustment (ECAC) proceeding, are included in the adopted rates. These revenue changes only impact SDG&E's electric department revenue requirement and result in a total decrease in SDG&E's electric rates of $121.0 million or 9.5%. The adopted rates are to become effective January 1, 1989 and will result in a net decrease for the typical residential customer using 425 kWh/month of $2.83 or 6.2%. Although SDG&E is authorized a total rate increase of $9.2 million or 2.1% for the gas department, rate changes for residential and other core gas customers will be deferred until SDG&E's annual cost adjustment proceeding (ACAP).

By this decision we continue our movement toward cost-based rates. Marginal energy, demand, and customer costs are developed and used in the revenue allocation process. Revenue allocation is based on an equal percent of marginal cost (EPMC) methodology aimed at providing accurate price signals related to energy consumption and discouraging uneconomic bypass.

Finally, this decision rejects the quantifying added uncertainty (QAU) methodology for depreciation, establishes a depreciation review procedure similar to represcription, rejects the incremental/decremental methodology for marginal customer costs, and awards intervenor funding.

INTERIM OPINION

Summary of Decision

This decision orders San Diego Gas & Electric Company (SDG&E) to reduce electric rates by $94.9 million or 7.5% and authorizes SDG&E to increase gas rates for non-core customers by $___ million or ___% and steam rates by $0.6 million or 61.3%.

Additionally, revenue requirement changes from the Application (A.) 87-07-044, San Onofre Nuclear Generating Station Units 2 & 3 (SONGS) pre-commercial operating date (COD) amortization and post-COD interim rate, and A.88-07-003, SDG&E's 1988 energy cost adjustment (ECAC) proceeding, are included in the adopted rates. These revenue changes only impact SDG&E's electric department revenue requirement and result in a total decrease in SDG&E's electric rates of $134.2 million or 10.5%. The adopted rates are to become effective January 1, 1989 and will result in a net decrease for the typical residential customer using 425 kWh/month of $3.22 or 7.3%. Although SDG&E is authorized a total rate increase of $8.3 million or 1.9% for the gas department, rate changes for residential and other core gas customers will be deferred until SDG&E's annual cost adjustment proceeding (ACAP).

By this decision we continue our movement toward cost-based rates. Marginal energy, demand, and customer costs are developed and used in the revenue allocation process. Revenue allocation is based on an equal percent of marginal cost (EPMC) methodology aimed at providing accurate price signals related to energy consumption and discouraging uneconomic bypass.

Finally, this decision rejects the quantifying added uncertainty (QAU) methodology for depreciation, establishes a depreciation review procedure similar to represcription, rejects the incremental/decremental methodology for marginal customer costs, and awards intervenor funding.

Introduction

Many of the revenue requirement items normally litigated in a general rate proceeding were agreed to in a Stipulation and Agreement and adopted in Decision (D.) 88-09-063. Additionally, cost of capital issues were bifurcated and consolidated with other energy utilities in a generic cost of capital proceeding. Appendix C lists a number of rate changes authorized in SDG&E's SONGS and ECAC proceedings. These changes are included in our adopted electric rates which will become effective January, 1, 1989.

D.88-09-063 provided for revisions to the adopted Stipulation and Agreement as a result of more recent information. Accordingly, we will revise the Stipulation and Agreement for the following:

1. Nuclear Regulatory Commission (NRC) fees, ($72,000)
2. Labor and non-labor escalation rates
3. Electric Power Research Institute (EPRI) dues, ($96,000)
4. Women/minority business enterprise (W/MBE) program costs, $200,000.

Two studies were required by D.87-12-069; reliability of service and a comparison of rates with other utilities. While the reliability of service study was submitted, the comparison study has not been completed. SDG&E is working with Pacific Gas & Electric Company (PG&E) and Southern California Edison Company (Edison) on the comparison study and by letter dated September 28, 1988 notified Administrative Law Judge (ALJ) Ferraro that the study should be completed by June 1, 1989. This proceeding will remain open to receive the joint comparison study.

Procedural Background

On December 1, 1987 SDG&E filed A.87-12-003 requesting authority to reduce rates for its electric department and increase rates for its gas and steam departments for test year 1989. SDG&E also requested attrition increases in 1990 and 1991 for all three departments. On January 7, 1988 a prehearing conference was held in San Diego. In March, 1988 there were two days of public participation hearings and between April and September, 1988 there were 21 days of evidentiary hearings.

Two interim decisions have been issued. D.88-07-023 replaced the $4.80/month residential customer charge for electric customers with a $5.00/month minimum bill and D.88-09-063 adopted the Stipulation and Agreement signed by SDG&E, Division of Ratepayer Advocates (DRA), Utility Consumers Action Network (UCAN), the City of San Diego, and Federal Executive Agencies (FEA) as resolution of most of the revenue requirement issues.

On June 14, 1988 a comparison exhibit was submitted which detailed the revenue requirement issues in the proceeding. An addendum to the comparison exhibit which addressed attrition issues was submitted on June 24, 1988. These items have been received as Exhibit 137.

Conservation/Load Management Adjustment Clause (CLMAC)

All expenses associated with conservation and load management programs are included in the adopted test year 1989 expenses. This will eliminate the need for CLMAC and requires the amortization of the current balance. SDG&E estimates that as of December 31, 1988 CLMAC will have overcollected electric revenues by $10.7 million and gas revenues by $3.6 million and recommends that the overcollections be amortized over three years, consistent with its general rate case cycle.

We will adopt SDG&E's recommendation and reduce its electric revenue requirement by $3.6 million annually and its gas revenue requirement by $1.2 million annually. In its 1990 attrition year filing SDG&E should amortize any difference between the estimated and actual CLMAC balance over two years.

Depreciation

Depreciation calculations as governed by DRA's (formerly Utilities Division) Standard Practice U-4: Determination of Straight-Line Remaining Life Accruals (U-4) have consistently been adopted by this Commission for ratemaking. U-4 provides a formalization of the theory of depreciation and the guidelines for performing the statistical analyses on which depreciation computations are based. An objective of this methodology is to recover a utility's original cost of depreciable fixed capital less net salvage value over the useful life of the asset. To achieve this objective the remaining life expectancy of depreciable plant must be periodically reviewed and when appropriate, adjusted. U-4 states:

> "Depreciation charges even in the simplest project should be re-examined from time to time. It is obvious that, until final retirement, those charges involve estimates of future life and salvage. . . . The remaining life method requires reappraisals and reviews of the estimates used from time to time." (U-4 at 42.)

SDG&E proposes that the remaining lives for 17 electric department plant accounts be adjusted by using a method referred to as QAU. This method was developed by SDG&E and adopted for the first time in its 1982 general rate case, D.93892. The QAU methodology has also been adopted in recent general rate cases for Edison and PG&E. Edison took a position in support of QAU in this proceeding.

DRA, FEA, UCAN, and the City of San Diego, collectively Opponents, oppose the use of QAU and as a result recommend a depreciation expense level which is $6.6 million lower than SDG&E's. UCAN, DRA, and the City of San Diego also recommend that three life extending programs be considered in developing the remaining lives for certain plant. This would lower SDG&E's requested depreciation expense by an additional $1.3 million.

Our rejection of QAU is not intended to signal utilities that depreciation analysts should isolate themselves from the input of experts. On the contrary, we prefer a process which solicits information from experts, provides their identity, describes their input, and indicates how the information was applied.

For telecommunications utilities the Federal Communications Commission (FCC) represcribes depreciation rates at three-year intervals. A telecommunications utility first submits proposed changes, including adjustments to average service lives, to DRA and FCC staff. After a detailed review of the initial proposal any changes recommended by DRA and FCC staff are discussed in a joint meeting at which subject matter experts are heard. If agreement is reached, the utility and DRA jointly recommend that the agreed upon depreciation factors be adopted. If agreement can not be reached, the telecommunications utility must file an application requesting approval of its depreciation study. This process is referred to as represcription.

Since depreciation rates for energy utilities are determined on a three-year cycle in general rate proceedings, it seems reasonable to adopt a procedure similar to represcription for them. Accordingly, we will require depreciation workshops to be held in SDG&E's future general rate cases. The workshops should be conducted after DRA has issued a report which analyzes SDG&E's depreciation proposal. We encourage SDG&E to bring subject matter experts to the workshops to justify adjustments which differ from those shown in DRA's report. Additionally, all interested parties should be invited to attend and participate in the workshop. Differences which remain after the workshops are concluded should be addressed in the general rate case hearings.

This procedure should provide for a more open process with direct input from experts in areas of dispute. It is also consistent with the represcription procedure used for telecommunications utilities. Finally, other major energy from our Order Instituting Rulemaking (R.) 87-02-026. Since R.87-02-026 resulted in General Order (G.O.) 156 which established a clearinghouse for the verification of W/MBEs, SDG&E requests authorization of the full $200,000. The remaining issues focused on the design and administration of SDG&E's W/MBE program. Public Advocates believes the participation of women and minorities in SDG&E's procurement contracts is inadequate and recommends that SDG&E:

1. Separately state goals for Filipino-Americans.
2. Consider adopting the major recommendations in Pacific Bell's Task Force Minority Report.
3. Employ an outside expert who can address SDG&E's failure regarding Blacks and Asians.
4. Independently verify W/MBE firms.
5. Develop greater management incentives for the achievement of W/MBE goals.
6. Increase the number of women and minorities in senior management.
7. Encourage joint ventures with W/MBEs and provide W/MBEs with technical assistance in meeting financing and insurance requirements at rates competitive with SDG&E's non-W/MBE contractors.

SDG&E is opposed to Public Advocates' recommendations stating that it has demonstrated a commitment to furthering, in a very rapid and dramatic way, W/MBE purchases over the next five years. SDG&E believes this is exemplified by its agreement in R.87-02-026 to accomplish a significant increase in the current level of contracts and purchases from women and minority-owned businesses. Additionally, SDG&E argues that:

Directly Assignable Costs

Directly assignable costs are investments which are identified as relating to customer access. SDG&E, DRA, and UCAN derived these costs by the TSM method. For each customer class except large time-of-use (TOU) and agricultural, TSM costs were determined by work orders from the operating districts. Engineering estimates for typical customer installations were used to derive costs for the large TOU and agricultural classes.

UCAN had a considerable number of recommendations concerning the development of directly assignable costs. Three of these were agreed to by SDG&E: (1) TSM costs should not reflect a contingency factor, (2) 4% should be used for purchasing and warehousing costs for transformers, and (3) a weighted average of single-family and multi-family units should be used to determine TSM costs for customers on schedule DR. UCAN's recommendations which were not agreed to are discussed below.

There are two issues concerning the weighting of single-family and multi-family units for determining TSM costs. First, UCAN recommends that the weighting should be based on incremental customers rather than DRA's use of average customers. Second, UCAN believes consideration should be given to cost-decreasing characteristics such as the number of overhead versus underground units and the number of coastal customers with lower usage.

For the single-family/multi-family DR schedule SDG&E agrees in principle with UCAN's position that a weighted average of single-family and multi-family units should be used to determine TSM costs. However, SDG&E recommends that DRA's calculation of 65.5% single-family units and 33.5% multi-family units based on test period housing stock be used. SDG&E argues that UCAN's weighted average of single-family and multi-family units does not reflect schedule DT (mobilehome) and DS (multi-family) customers.

Since we are developing marginal customer costs for an existing system, it would be inappropriate to use a weighting of incremental customers, as suggested by UCAN. We will adopt DRA's weighted average of single-family and multi-family units. For its second recommendation, UCAN did not present a methodology or sound theoretical basis for reflecting the characteristics it identified as cost-decreasing. We will not adopt this recommendation.

UCAN claims that there is an inconsistency between the 129% labor overhead rate SDG&E used for meter installations and the 111% labor overhead rate used on work orders for customer costs. Additionally, UCAN argues that SDG&E did not explain the inconsistency and only one overhead factor should be in effect at a time. As a result, UCAN recommends that the 111% rate be used.

SDG&E disagrees that labor overhead associated with indirect labor should be reduced form 129% to 111% and provided an exhibit detailing the calculations of its 129% labor overhead rate. However, SDG&E did not give an explanation for the difference between the two labor overhead rates. Without this explanation we are unwilling to adopt the higher labor overhead rate. UCAN's recommended labor overhead rate of 111% will be adopted.

UCAN believes that SDG&E overestimated the cost of purchasing transformers and recommends that UCAN'S lower estimates developed from SDG&E's purchase contracts be used. SDG&E is opposed to UCAN's estimate of transformer costs and recommends that a moving average inventory price be used.

A moving average of inventory is an appropriate method for determining the plant investment associated with transformers being placed in service, but does not strictly adhere to marginal cost principles. Since SDG&E did not dispute the transformer costs represented by its purchase contracts, we will adopt these as representative of the incremental cost of transformers.

SDG&E calculated a real fixed rate of 10.38% which it used to annualize TSM investments. UCAN recommends a 9.78% rate. This rate was calculated by excluding three FERC accounts which UCAN considers unrelated to TSM investments. DRA calculated a 10%

rate after excluding two of the three FERC accounts UCAN questioned. DRA considers the third FERC account, which covers protective devices and capacitors, to be related to TSM investments and included it in its calculation. During the proceeding SDG&E changed its position and now supports DRA's 10% real fixed rate.

We find DRA's argument that protective devices and capacitors are related to TSM investments persuasive and will adopt its recommended real fixed rate of 10%.

Common Distribution Costs

The classification of common distribution costs as either demand or customer-related was a major area of controversy. SDG&E estimated the customer-related portion of common distribution costs using a proxy for the "minimum distribution system" method. This method assumes that 50% of non-energized facilities and 25% of energized facilities required to provide customers with access through the distribution system are customer-related.

In support of its methodology SDG&E argues that:

1. Although the estimates of common distribution costs are judgmental and not subject to independent verification, many marginal costs are not subject to precise calculation. Achieving a result that is approximately correct is superior to ignoring a marginal cost principle.

2. TSM costs are classified as customer related because they can be directly identified with facilities dedicated to serving individual customers.

3. The proxy for the "minimum distribution system" is intended to represent common distribution costs which are dedicated to the service of customers as distinguished from meeting their demands.

4. For the common distribution element of customer-related costs, data is taken from FERC accounts over a 12 year period in constant dollars then divided by the number of customers to derive a proxy for common

> distribution costs. SDG&E's methodology does not double count by taking a percentage of FERC accounts from any particular year or set of work orders.

Since UCAN, DRA, and SDG&E have accepted secondary distribution lines as a customer-related component of marginal customer costs, UCAN believes that only the TSM costs recommended by DRA should be included as customer costs. Additionally, UCAN opposes SDG&E's inclusion of common distribution costs because it: (1) results in double-counting of some costs, (2) is based on embedded cost data, and (3) allocates costs by number of customers rather than demand. Finally, UCAN states that Exhibit 89, which eliminates double-counting from SDG&E's common distribution costs, is not based on the same allocation percentages used in SDG&E's original testimony.

We prefer the approach of identifying specific equipment as access related and assigning the investment costs directly to the appropriate customer class. While there is not a clear line of distinction between demand and customer related equipment, we believe the TSM method provides us with the best approximation. Accordingly, we will treat common distribution costs as demand-related.

<u>Customer Accounting Costs</u>

SDG&E estimated customer accounting costs for the forecast period and then allocated them to customer classes using weighting factors for each FERC account. UCAN recommended three adjustments to the customer accounts and collections costs included in SDG&E's marginal cost study. First, UCAN identified a discrepancy between customer accounts and collections costs in SDG&E's marginal cost study and the costs in SDG&E's results of operation showing. UCAN acknowledges that this discrepancy was corrected by both SDG&E and DRA.

Second, UCAN maintains that SDG&E has failed to consider the significant differences in the cost of reading meters among various customer classes. UCAN recommends that meter reading weighting factors that SDG&E developed and used in the past be adopted in this proceeding.

Finally, UCAN states the Commission has a long-standing policy to exclude conservation and marketing programs from marginal customer costs and recommends that they be excluded in this proceeding.

In response to UCAN's proposed corrections, SDG&E states that:

1. The largest correction, which addresses the inconsistency between SDG&E's marginal cost calculation and the results of operation calculation, has been corrected in Exhibit 63-3-A.

2. No correction is warranted for conservation-related expenses and residential meter reading. Conservation expenses are customer-related and should be reflected in customer accounting costs. Reductions in residential meter reading costs are undocumented and should not be adopted.

Obviously there is a difference in the cost of reading meters for the various customer classes. Since SDG&E apparently developed weighting factors in the past which represented the cost differential of reading meters for each class, we will use these weights. UCAN is also correct that we have a long-standing policy of excluding conservation and marketing programs from marginal customer costs. SDG&E has not attempted to justify a change in this policy. We will adopt both UCAN adjustments for customer accounting costs.

Incremental/Decremental Marginal Customer Costs

UCAN states that one of the fundamental premises of marginal cost pricing is that it can simulate a competitive market where none exists. Ideally, UCAN would simulate a competitive market for determining the costs of customer access equipment by collecting customer investment costs through a hookup charge for new customers or through simulated purchases of access equipment by all customers. In this proceeding UCAN proposes an incremental/decremental methodology that reflects a hookup charge for new customers and decremental costs for existing customers. UCAN believes that this methodology, which reduces customer investments by 27%, provides a more accurate estimation of costs imposed by existing and new customers than the proposals of other parties.

Under UCAN's proposal hookup charges for new customers would be assigned to the appropriate customer class for revenue allocation. Once a hookup charge is collected through rates there would be no further revenue responsibility for that access equipment. The access equipment investment costs for existing customers would be based on the cost to the utility if the customers were to leave the system.

In response to DRA's rental market approach, UCAN argues that it does not properly reflect a fully competitive market in which customer ownership of access equipment would prevail because it is cheaper to buy equipment than rent it.

SDG&E is opposed to the UCAN's incremental/decremental approach to marginal customer costs as proposed by UCAN for the following reasons. UCAN's approach assumes that:

1. Customers would be able to buy new access equipment at an annual cost below SDG&E's charges.

2. Existing access equipment is worth less to customers than new equipment.

3. SDG&E would not sell new access equipment.

4. Customers would finance access equipment only at fixed interest rates. Renters are not taken into consideration.

5. Based on judgment, a 25% salvage value is appropriate for SDG&E's access equipment.

DRA believes the objective of marginal cost pricing is to simulate competitive market results and that UCAN's incremental/decremental method is not a market-related theory. In opposition to UCAN's method DRA argues that:

1. It has significant reservations concerning safety, liability, and general customer interest in an outright customer purchase option.

2. Most customers are likely to remain as renters of access equipment in the foreseeable future.

3. Its rental market approach would exclude residential customers who purchase access equipment. This is currently done for other customer classes.

4. It is extremely unlikely that competitive providers could furnish access equipment at only 25% of SDG&E's estimated costs. This is a basic assumption in UCAN's methodology.

UCAN agrees that DRA's rental market approach would result in prices that equal the incremental customer cost if it represents a truly competitive marketplace. UCAN argues that in a truly competitive market customers would have the option of purchasing or renting access equipment, but that DRA's approach only assumes a rental option. Because of the deductibility of mortgage and business interest, UCAN believes that purchasing equipment is cheaper than renting and that in a competitive market purchases would prevail and rentals would be scarce. Thus UCAN concludes that a rental market approach does not represent a competitive market and should not be used in determining marginal customer costs.

In evaluating UCAN's criticism, we conclude that its own proposal does not correctly represent the cost of customer ownership. We believe it is unrealistic to expect competitive providers of access equipment to be able to undercut SDG&E's investment costs by 75%. We are also not convinced that a substantial number of customers would choose to purchase this kind of equipment. Aside from potential operational and safety concerns, many customers would likely choose to rent rather than buy for convenience and reliability.

If expanded customer ownership is shown to be practical, DRA's proposal to exclude such customers from the allocation of access equipment is a logical and reasonable solution. This is currently the practice for industrial and large commercial customers which purchase access equipment.

Finally, we believe the most appropriate methodology for determining the cost of access equipment is DRA's rental market approach. We recognize that our rejection of the incremental/decremental methodology contradicts the discussion contained in D.86-08-083, PG&E's 1986 ECAC proceeding. However, the proceedings over the last two years have given us an opportunity to understand the marginal cost principles involved with marginal customer costs better than we did two years ago. Accordingly, it is now clear that the incremental/decremental methodology is not consistent with our marginal cost principles as discussed above.

Marginal Revenue Determinants

Marginal revenue determination is a critical aspect of the marginal cost and revenue allocation process. Marginal costs are multiplied by marginal revenue determinants to determine marginal cost revenues. These are the revenues the utility would collect if all customers were charged their marginal costs instead of rates adjusted for the utility's revenue requirement. Marginal revenue determinants are developed for energy, customer and demand. Marginal revenue determinants for demand are further divided into generation, transmission, and distribution. Most of the differences among the parties centered around marginal revenue determinants for demand. We will discuss each of the marginal revenue determinants below.

Marginal Energy Revenue Determinants

SDG&E and FEA agreed to DRA's marginal energy revenues, as shown in Exhibit 63. However, during the hearings DRA revised the marginal energy revenues in Exhibit 63 to reflect a revenue-related tax factor which was inadvertently omitted. We will adopt DRA's marginal energy revenues revised to reflect the appropriate revenue-related tax factor.

Marginal Demand Revenue Determinants

The parties do not agree on the appropriate marginal demand revenue determinants to be used for revenue allocation. There are four areas of disagreement: (1) annual demands versus demands by time period, (2) reliability adjustment for generation demand, (3) diversity factors for the residential and small commercial classes, and (4) demand loss factors.

SDG&E used load research data to determine demand levels by class and TOU period, and coincident and non-coincident non-diversified demands by voltage level. The weighting factors for each marginal demand revenue component were derived following the method used in the Edison general rate case decision, D.87-12-066. The annual marginal demand revenue component was calculated for each class by multiplying the appropriate TOU period demand by each marginal demand cost. The results were summed across all time periods and demand types for that class.

DRA's methodology differs from SDG&E's in that: (1) average annual demands are used instead of demands by TOU period, (2) a reliability adjustment is applied to generation demand, and (3) a diversity factor is used to determine transmission, and distribution demand. With the exception of distribution demand, UCAN adopted DRA's marginal revenue determinants to calculate its marginal cost revenues. FEA only took issue with DRA's and UCAN's transmission and distribution demands.

Except for DRA's reliability adjustment and diversity factor for residential class transmission and distribution demands, we will adopt DRA's methodology, weighting factors, and demand determinants for calculating marginal cost revenues. Below, each of the issues involving marginal revenue determinants is discussed.

Annual Versus TOU Demand

DRA asserts that although it is appropriate to calculate marginal energy costs by time periods, it is inappropriate to do so for marginal demand cost revenues. DRA states that investments in generation, transmission, and distribution systems do not vary by time period. Additionally, DRA claims that the use of time periods to calculate demands is unnecessary and would amount to sizing SDG&E's system for average demand. While FEA and UCAN support DRA's use of annual demands, SDG&E recommends that demand cost revenues be calculated by time period. We recognize that marginal demand costs by TOU period are used for rate design, however, SDG&E has not convinced us that they are also needed for revenue allocation. We will use annual demands to calculate marginal demand cost revenues.

Reliability Adjustment for Generation Demand

DRA made a reliability adjustment for generation demand cost revenues by taking the sum of loss of load probability-weighted (LOLP-weighted) demands for each class and multiplying them by the generation level marginal costs. DRA states that reliability adjustments are used for the calculation of marginal demand cost revenues and avoided cost payments and that a similar adjustment was adopted in Edison's last general rate case decision. SDG&E is opposed to DRA's reliability adjustment. It states that

DRA's LOLP-weighted generation demand of 1992 megawatts (MW) is too low and recommends that the 1986 recorded system peak of 2376 MW be used.

We are not opposed to the use of a reliability adjustment factor, however, in this proceeding DRA's generation demand is much lower than recorded 1986. From the record it is not clear why this occurred, but it could be a problem with the available data. Accordingly, we will adopt the recorded system peak of 2376 MW as the best representation of generation demand for 1989.

Transmission and Distribution Demand

All parties used DRA's methodology for the calculation of transmission and distribution demands. DRA's methodology is based on the hypothesis that the demand seen by the transmission system is a weighted average of coincident and non-coincident demand for each rate class. Similarly, the demand seen by the distribution system is also a weighted average of these demands. The differences between the parties focused around: (1) weighting factors for calculating transmission and distribution demand and (2) coincident and non-coincident demands used for calculating transmission and distribution loads.

Although all parties used DRA's methodology for calculating weighting factors, SDG&E and FEA used different data in deriving their weighting factors. We will adopt DRA's weighting factors which are consistent with the adopted demand determinants.

SDG&E believes that the proper non-coincident demand to use for all classes is non-diversified. DRA uses non-diversified, non-coincident demand to measure the load placed on the distribution system by customers in all but the residential and small commercial classes. DRA uses diversified non-coincident demand for the residential class and an average of diversified and non-diversified, non-coincident demand for the small commercial class. FEA used an average of diversified and non-diversified demands for both the residential and small commercial classes, while UCAN essentially used DRA's methodology.

DRA believes that a diversified demand is appropriate for the residential and small commercial classes because the final line transformer serves multiple customers. While DRA was unable to acquire specific data from SDG&E concerning the number of residential customers served by each transformer, it assumed an average of 20 customers were connected to each transformer. DRA based its assumption on talking with load research experts and data from other utilities. Assuming 20 customers are connected to each transformer, DRA calculated a diversity factor of 25% of non-diversified, non-coincident residential load. A 25% diversity factor assumes that no more than 25% of the maximum load of all individual customers connected to any residential transformer will occur at the same time.

Although SDG&E did not provide data to support its argument that DRA's assumption of 20 customers connected to each transformer is too high, it asserts that fewer than 10 customers are likely to be connected to a new transformer. As a result, SDG&E considers DRA's 25% diversity factor to be unrealistic. Additionally, SDG&E states that its distribution planning manual instructs planning engineers to use a diversity factor between 55% and 75% when 10 customers are connected to one transformer. Finally, although UCAN did not develop a diversity factor, its witness testified that the appropriate diversity factor is probably between 50% and 75%.

Additionally, FEA takes exception to UCAN's and DRA's transmission and distribution demands. FEA states that the peak load on the transmission system must be equal to or greater than the system peak, but that DRA uses only 2,650 MW for transmission demand while test year 1989 peak demand is 2,778 MW. FEA also criticizes DRA's and UCAN's use of 3,385 MW and 3,174 MW, respectively, for distribution demand. FEA recommends a distribution demand of 4,400 MW based on the average substation peak which includes average class peaks and individual customer peaks. Since DRA's and UCAN's estimates do not reflect individual customer peaks, which play a major role in sizing various elements of the distribution system, FEA concluded that they do not appropriately represent distribution demand.

UCAN argues that: (1) FEA's demand allocators do not adequately reflect the diversity among classes with small customers, (2) FEA's witness conceded that the class non-coincident peak does not affect the design of the distribution system, and (3) SDG&E and FEA urge the use of the same method. Finally, UCAN concludes that DRA's method is reasonable.

We believe it is appropriate to consider a diversity factor for residential and small commercial classes. However, without data on the average number of customers served from each of SDG&E's transformers, we are unwilling to adopt DRA's 25% diversity factor. Based on SDG&E's planning manuals and UCAN's testimony, we consider a 50% diversity factor for the residential class reasonable for this proceeding. Since the only dispute with the diversity factor for the small commercial class was its use, we will adopt DRA's diversity factor for this class.

Demand Loss Factors

DRA pointed out that the demand loss factors used by SDG&E were less than the on-peak energy loss factors and in error. In response to DRA, SDG&E agreed to conduct a new study of demand and energy loss factors to address DRA's concerns.

Consistent Demand Determinants

Some parties are concerned that there may not be consistency among the demand determinants used for marginal cost, weighting factors for transmission and distribution demand, and revenue allocation. Although DRA, UCAN, and FEA agree that there should be consistency among the demand determinants, DRA and UCAN only appear to be concerned if a lack of consistency causes a significant difference in the final revenue allocation. We agree with DRA's and UCAN's position and will endeavor to use consistent demand determinants in the marginal cost and revenue allocation calculations.

Marginal Customer Revenue Determinants

SDG&E and DRA stipulated to the number of customers in each class and no other party took issue with their agreement. Differences in total marginal customer-related revenues are only due to differences in unit marginal customer-related costs. We will adopt SDG&E's and DRA's stipulation on the number of customers in each customer class.

Revenue Allocation

Revenue allocation is the process by which SDG&E's adopted revenue requirement is allocated to the various customer classes. In recent years we have followed a policy of using marginal cost principles in revenue allocation and as a guideline for rate design. Economic theory dictates that marginal cost pricing allows the customer to trade-off usage of electricity with consumption of other resources or to increase or decrease usage based on the incremental cost of producing electricity. Marginal cost pricing also provides equity in rates, by relating costs imposed on the electric system with the customers who are responsible for those costs.

Since revenues based on marginal costs are not usually equal to the utility's revenue requirement, a method must be used that allows us to reflect marginal cost principles while still collecting the authorized revenue requirement. The method used in recent years to reconcile marginal costs with revenue requirement is EPMC. This approach allocates revenues so that each class is an equal percent of its marginal cost revenues. This is referred to as full or 100% EPMC.

D.87-12-069 in SDG&E's most recent ECAC proceeding adopted EPMC with the constraint that each customer class receive a minimum 5% rate decrease. Although residential and agricultural revenues were below the EPMC allocation for their respective class, we lowered all rates in the context of a $141.2 million decrease. In that decision we stated:

> "We believe that SDG&E's rates must be restructured and moved towards marginal costs in a deliberate and careful manner. Our adopted revenue allocation makes significant movement towards the adopted marginal costs and allows time for the refinement of marginal cost studies in future proceedings." (p. 2, D.87-12-069.)

DRA and FEA recommend a full EPMC revenue allocation without constraints, while SDG&E and UCAN recommend a capped EPMC allocation. Below is a discussion of each party's recommendation for revenue allocation with the exception of street lighting. Revenue allocation for the street lighting class will be addressed in the rate design section.

SDG&E's Position

SDG&E's preferred revenue allocation which assumes a decrease in electric revenues of $49.4 million or 3.9% would decrease revenues to the residential class by $30.0 million or 5.4%. Other classes would be decreased by 0.9% for large TOU, 2.0% for very large TOU, 8.9% for agricultural and 3.9% for all others.

SDG&E also proposed a revenue allocation based on DRA's recommended decrease of $88.9 million. If DRA's $88.9 million decrease is adopted, SDG&E recommends decreases of 6.8% for residential, 8.1% for very large TOU, 12.1% for agricultural, and 7.1% for others.

SDG&E's guiding principles for placing constraints on an EPMC revenue allocation are as follows: (1) employ as few constraints as possible, (2) give all classes a decrease, and (3) for rate stability, change no class more than plus or minus 5% of the system average percent change (SAPC). Application of these principles provides for rate decreases from 2.0% to 8.9%, which SDG&E states allows for steady but moderate movement toward full EPMC rates.

DRA's Position

DRA recommends a full EPMC revenue allocation which it states is consistent with our general policy of marginal cost-based rates. DRA believes that SDG&E's method of determining caps for various rate classes is arbitrary because there is no consistency between SDG&E's recommended decreases for the residential class at different system average percent decreases.

FEA's Position

FEA supports the movement toward full EPMC revenue allocation, and opposes SDG&E's proposal because it does not result in significant movement toward this objective. FEA believes that full EPMC is substantially easier in this proceeding because there is an overall revenue decrease.

UCAN's Position

UCAN proposes an EPMC allocation capped at 5% above SAPC. Based on UCAN's revenue allocation the cap applies to rate schedules AD and AL. If the overall decrease is between 4% and 6%, UCAN would deviate from the 5% cap by recommending no rate change in classes where rate continuity can be provided.

Additionally, UCAN states that there is a higher value of service and outage costs to commercial and industrial customers and that this is not reflected through traditional EPMC methodology. Accordingly, UCAN recommends that the large customer classes be charged for higher generation reserve margins and greater distribution system costs.

Discussion

The adopted electric base rate decrease of $89.3 million plus $31.7 million from SDG&E's SONGS and ECAC proceedings affords us the opportunity to implement a full EPMC revenue allocation methodology. We believe DRA's and FEA's EPMC revenue allocation proposals are the only ones that are consistent with our goal of providing customers with rates based on the cost of providing electric service. Their methodology is consistent with our goal of full EPMC revenue allocation as stated in Edison's and PG&E's recent general rate case decisions and adopted for SDG&E in D.87-12-069.

The spread from the SAPC decrease of 10% using full EPMC revenue allocation, ranges from a 6% decrease for residential customers to an 18% decrease for agricultural customers. Since most customer classes are clustered within plus or minus 4% of SAPC and no class has a decrease greater than 18%, we will not cap our adopted EPMC revenue allocation.

We also will not adjust the adopted EPMC revenue allocation for UCAN's recommendation that large customer classes be charged for higher generation reserve margins and greater distribution system costs for the following reasons:

1. We are not convinced that SDG&E's generation reserve margins or its distribution system are designed to provide customer classes with varying degrees of reliability.

2. UCAN has not developed a methodology for implementing its recommendation.

3. UCAN's adjustment is not appropriate for revenue allocation and should be addressed in the calculation of marginal demand costs.

Our adopted revenue allocation by class is shown in Appendix D. It reflects the general rate case revenue decrease and the revenue changes from SDG&E's SONGS and ECAC proceedings as shown in Appendix C.

<u>Electric Rate Design</u>

The following sections will discuss residential, commercial, industrial, agricultural, and street lighting rate design issues. For these classes the most heavily contested matters were rate schedules AD, AL-TOU, and A6-TOU, SDG&E's power factor adjustment, standby service, and street lighting.

D.88-07-023, dated July 11, 1988, replaced the $4.80 customer charge for residential customers with a $5.00 minimum charge. This matter will not be readdressed in this decision. The realignment of baseline and non-baseline residential rates in compliance with Senate Bill (SB) 987 (Ch. 212, Stats. 1988) is being addressed in Order Instituting Investigation (I.) 88-07-009 and is not at issue in this proceeding. Our adopted gas and electric residential rates reflect D.88-10-062 in I.88-07-009. The two-month undercollection of electric rates authorized in that proceeding is terminated effective with this decision.

Residential

While SDG&E's application contained a number of controversial proposals, SDG&E has either withdrawn its proposals or the parties have reached agreement on all but two items; baseline allowances and an increase in the returned check charge.

The only disagreement concerning baseline allowances is DRA's recommended continued phase-in to capture changes in average aggregate consumption. This procedure was adopted in SDG&E's last general rate case and DRA believes that Public Utilities Code (PU) § 739 requires its continuation. SDG&E argues that changes in baseline allowances will create an upward pressure on residential bills and, if changes are adopted, they should not be implemented until May 1, 1989, when seasonal baseline changes occur.

We agree with DRA that continued phase-in of electric baseline allowances meets the requirements of PU § 739 and we will adopt its recommendation. Baseline quantities will be reduced over a one to three-year period starting May 1, 1989. The adopted baseline allowances are shown in Appendix F.

The second issue is SDG&E's request to increase the current charge of $6 for a customer's returned check to $10. SDG&E

based its request on bank charges which make up 59% of SDG&E's proposed $10 charge, the cost of processing, collection, and preparation of checks to be redeemed; and the cost of key punching for redeemed checks, materials, and postage.

UCAN opposes an increase in the charge for returned checks stating that SDG&E: (1) did not justify which costs have increased since the $6 charge was implemented, (2) did not identify what measures it has taken to reduce bank fees, and (3) may not monitor returned check policies properly.

Although SDG&E has provided an itemized list of the items which comprise its returned check charge, SDG&E has failed to convince us that it is unable to negotiate lower bank fees for returned checks. Without SDG&E's assurance we can not be certain that an increase in the returned check charge is reasonable. We will not approve an increase in the returned check charge.

The agreements among the parties on the following matters appear reasonable and will be adopted:

1. SDG&E, WMA, and DRA agree that the discount for mobilehome parks on schedule DT should be $9.50/unit/month or $0.312 on a daily basis.

2. SDG&E and DRA agree that the discount for apartment buildings on schedule DS should be $4.04/apartment/month or $0.110 on a daily basis.

3. DRA, SDG&E, and UCAN agree with the DR-TOU rate design in Exhibit 96.

4. DRA agrees with SDG&E's proposal for experimental schedules DA-TOU and DU-TOU. These schedules are designed in relation to schedule DR-TOU with a 2:1 peak to off-peak ratio.

5. SDG&E has withdrawn the following residential rate design proposals: (1) late payment charge, (2) telephone charge with respect to bill collections,

(3) customer charge, and (4) reconnection charge for the period when service is disconnected.

For the reconnection charge SDG&E had proposed to require a customer who leaves and returns to the system within a short period to pay the customer charge that would have been assessed if the customer had remained on the system. Center for Public Interest Law (CPIL) mailed testimony to all parties, except SDG&E, opposing SDG&E's proposal on April 15, 1988. SDG&E was hand delivered CPIL's testimony on April 25, 1988. On April 27, 1988 SDG&E recommended that the customer charge be eliminated for residential customers and withdrew its proposal to to assess customer charges for the time customers were off the system.

Small and Medium Commercial

The principal small and medium commercial schedules are A and AD. No structural changes are proposed for schedule A. Schedule AD was closed to new customers on July 1, 1987. Existing customers on this schedule have the option to remain on the schedule or move to the AL-TOU schedule. AL-TOU is a time-of-use rate schedule with rates which more closely reflect SDG&E's costs.

SDG&E proposes to modify the AD schedule by establishing a two tier declining block energy rate. The first tier rate is charged for the first 300 kilowatt (kW) hours consumption per kW of demand. The lower second tier is charged for usage in excess of that amount. SDG&E has designed the energy rates for this schedule to be similar to Edison's GS-2 schedule, which serves equivalent customers.

SDG&E makes this two tier AD energy rate proposal for the following reasons. First, it provides an incentive for customers to improve their load factors by controlling their demand. Second, the rate structure recognizes the level of customer demands placed on the system. Third, it emulates TOU rates without the expense of

TOU meters. Fourth, it brings the tail block or tier II rate closer to, but not below, marginal cost.

In response to concerns expressed by other parties, SDG&E argues that: (1) its proposal will not increase energy consumption, because there is no ratchet provision, and (2) standby rates should only be available to TOU customers, but any customer with a demand above 20 kw can move to the AL-TOU rate schedule. Finally, SDG&E states that DRA's proposal is an acceptable alternative, if the two tiered energy rate structure is not adopted.

DRA recommends that the monthly demand charge on the AD schedule be increased from $5.00/kw to $5.50/kW to reflect marginal capacity costs more closely. DRA is opposed to SDG&E's two-tiered proposal, because it cannot reconcile SDG&E's declining block rates with cost-based rate design principles. Although SDG&E's rate design purports to collect capacity costs in higher tier I rates, DRA believes that the customer perceives declining block rates as a signal that the more energy used the less it costs.

In addition to DRA, Independent Power Corporation (IPC), Department of General Services of the State of California (General Services), Small Cogenerators of California (SCC), Poway Unified School District (Poway), San Diego Mineral Products Industry Coalition, and UCAN are opposed to SDG&E's declining block energy rates. Many of the concerns of these parties are similar. Generally, they argue that:

1. Two-tiered rate designs are not in conformance with cost-based rate design principles.

2. Declining block rate structures are inconsistent with conservation policies.

3. AD customers which take all their energy off-peak would not be able to emulate TOU rates.

4. Lowering the effective rate for higher load factor customers will discourage migration to a TOU rate schedule.

5. SDG&E's AD schedule is not cost-based.

6. SDG&E's proposal will have a significant adverse impact on the economics for small scale cogeneration.

These parties are also concerned with DRA's proposal to increase the demand charge on the AD schedule, because: (1) many AD customers have low load factors and will see overall rate increases, and (2) the AL-TOU schedule offers no relief for these customers from increased rates. Finally, IPC recommended that, if a declining block rate structure is adopted, a special condition be added that allows customers which have the ability to self-generate to displace the higher, first-tier rate.

Although we support SDG&E's rate design principles for its two-tier AD rate, we consider its proposal inconsistent with them. SDG&E's proposal would create an inequity for AD customers which use more off-peak energy than the schedule's average and/or do not have second tier usage. This occurs because greater off-peak usage for these customers will not result in the emulation of TOU rates, and customers with only first tier usage will not have their incremental consumption priced at marginal cost. These inequities coupled with the concerns expressed by the parties are sufficient justification for not approving SDG&E's proposed changes to the AD rate schedule.

DRA states that its proposal to raise the AD demand charge from $5.00/kw to $5.50/kw, while not cost-based, moves in that direction. Since this is consistent with our objective of cost-based rates, we will adopt DRA's recommended increase in the demand charge for the AD schedule.

Finally, IPC recommends that all schedule A and AD customers have the option of TOU rates. Since SDG&E's witness testified that it was reasonable to provide a TOU option to these customers, we will allow schedule A and AD customers to move to a TOU schedule.

Large Commercial/Industrial

AL-TOU and A6-TOU

D.87-12-069 in SDG&E's 1987 ECAC proceeding adopted major changes for commercial and industrial customers served under rate schedules AL-TOU and A6-TOU. These changes, which provide for higher demand charges and lower energy rates, were the result of a stipulation in that proceeding.

The AL-TOU tariff consists of a customer charge, a non-coincident or non-time-related demand charge subject to a 50% ratchet, summer and winter peak demand charges, and energy charges differentiated by voltage levels for summer and winter. A6-TOU is a variation of AL-TOU. It includes the same non-coincident demand and energy charges, but a higher customer charge and higher peak demand charges for summer and winter to reflect customer demands at the time of each month's system peak. A rate limiter of $0.16/kWh also applies to both schedules. The stipulation referenced above included two levels of demand charges. D.87-12-069 adopted the lower level stating:

> "We adopt the lower set of demand charges proposed by all parties other than SDG&E because we prefer to move gradually towards the complete recovery of SDG&E's estimated fixed costs in fixed charges. These costs will be more closely examined in the general rate case." (p. 26, D.87-12-069.)

SDG&E requests that the higher level of demand charges contained in the stipulation be adopted, because the AL-TOU and A6-TOU schedules recover less than the marginal costs associated with those services. Additionally, SDG&E recommends that the energy rates be derived using the same model employed in the stipulation.

No changes are recommended by SDG&E or other parties to the rate limiter or ratchet percentage.

DRA states that its AL-TOU and A6-TOU rate design including the relationships between on-, mid-, and off-peak energy rates maintains the structure adopted in D.87-12-069. DRA argues that an increase in demand charges is unwarranted because marginal capacity costs are less than those used in the AL-TOU and A6-TOU negotiations.

FEA supports DRA's position stating that D.87-12-069 significantly increased the demand charges for these rate schedules and introduced a new maximum demand charge. Although FEA recognizes that additional movement is necessary to fully implement EPMC at the schedule level, it recommends maintaining the current level of demand charges and decreasing the energy charges to reflect the decrease in revenue requirement.

General Services, while not a signatory, did support the stipulation adopted in D.87-12-069. General Services states that its support for the stipulation was based on a revenue reduction of between $63 and $83 million, but a decrease of $141.2 million was adopted. Because of the amount of the decrease adopted in D.87-12-069 and the possibility of a significant decrease in this proceeding, General Services recommends a proportionate decrease in demand and energy charges.

SCC also recommends a proportionate reduction in demand and energy charges. SCC believes this will avoid peak-clipping and allow lower load factor customers.

Finally, Poway recommends a change from the on-peak period of 11:00 a.m. to 6:00 p.m. in summer to 12:00 noon to 6:00 p.m. Poway states that the current on-peak summer period causes a financial hardship on school districts which normally end summer classes by 12:00 noon, but pay on-peak demand charges as if they operated during the entire on-peak period. As a result of Poway's concerns DRA and SDG&E have addressed this issue in more detail in SDG&E's current ECAC proceeding A.88-07-003. We will defer resolution of this matter to that proceeding.

Since considerable movement toward cost-based demand charges was made in D.87-12-069, we are reluctant to make additional changes now. We believe DRA's proposal of only adjusting energy charges to reflect changes in revenue requirement, which is supported by FEA, is a more reasonable approach to follow. This will allow continued, but moderate, movement toward cost-based rates.

We also consider it more appropriate to maintain the current relationship of the off-, mid-, and on-peak energy rates than use SDG&E's model which developed this relationship for the stipulation. While the parties to the stipulation may be aware of the workings of the model, most commercial and industrial customers are not. Maintaining the existing relationships should foster a clearer understanding and increase the acceptance of the adopted rates.

AO-TOU and AO6-TOU

AO-TOU and AO6-TOU are optional rate schedules which were closed to new customers as of July 1, 1988. SDG&E proposes that the customer and demand charges for these schedules be maintained at their current levels and the energy rates for each time period be reduced by an equal percent. No party opposes SDG&E's proposal.

We will adopt SDG&E's recommendation for the AO-TOU and AO6-TOU schedules. Since these were established as optional schedules in 1986 and are closed to new customers, we will require SDG&E to address their continued appropriateness in its next general rate proceeding. We will also require SDG&E, after its rate design exhibits are filed in the next general rate proceeding, to notify all customers on these schedules that the continuation of the schedules will be an issue in the proceeding.

Interruptible Service

Interruptible service schedules provide customers with a credit for interruptible demand that is in excess of their contracted level of firm service. These credits are based on schedule AL-TOU peak period demand charges. DRA and SDG&E agree that the interruptible credits should be revised to reflect changes in the demand structure of the AL-TOU schedule. SDG&E proposes to modify the credits by maintaining the relationship between the credits and the on-peak demand charges. DRA contends that the credits should be based on SDG&E's marginal capacity costs because demand charges may contain more than coincident capacity costs.

Although there is only a small difference between DRA's and SDG&E's recommended interruptible credits, we conceptually prefer DRA's approach and will adopt its methodology.

AE-1, R-TOU-1, and R-TOU-2

AE-1, R-TOU-1, and R-TOU-2 are experimental real time pricing schedules established in 1986 with a termination date of January 1, 1992. The structure of these rate schedules differs from other TOU rates in that on-peak charges only take effect when the system load reaches a predetermined level. The predetermined level or trigger point is adjusted annually by an advice letter filing.

SDG&E proposes to retain the existing rate structure and adjust only the mid- and off-peak energy rates. Although previous adjustments were not always consistent with the originally adopted design philosophy, SDG&E proposes to maintain the original philosophy by reducing the mid- and off-peak energy rates and equating the off-peak energy rates for the three schedules.

To maintain these schedules as viable and cost-effective alternatives, DRA recommends three adjustments to the rate structure. First, the mid-peak demand charge should be replaced by the maximum demand charge adopted for AL-TOU and A6-TOU. Second, the on-peak energy rate on AE-1 should be reduced significantly to accurately reflect marginal costs. Finally, the contract minimum demand charge should be reduced in response to changes in marginal capacity costs.

DRA argues that these rate schedules were designed to test real time pricing using the AL-TOU and A6-TOU rate structures that existed at the time. Since AL-TOU and A6-TOU underwent major changes in D.87-12-069, DRA believes that the real time pricing schedules should be revised to reflect the adopted changes.

Additionally, DRA recommends that customers on AE-1, R-TOU-1, and R-TOU-2 be permitted to switch schedules without restriction until July 1, 1989 and that the expiration date for these schedules be extended until January 1, 1993. This would: (1) allow for review of these schedules in SDG&E's next general rate proceeding, (2) provide customers the 12-month notice of termination called for in special condition 14, and (3) permit customers to react to recent and proposed rate changes.

While there is no price certainty implied in these rate schedules, we believe it is reasonable for customers to expect some consistency in the design criteria during the experiment. However, we agree with DRA that real time pricing schedules should reflect the rate structure of AL-TOU and A6-TOU, otherwise it would be unclear whether customer actions were influenced by the existing rate structure or real time pricing. Accordingly, AE-1, R-TOU-1, and R-TOU-2 will be closed to new customers on the effective date of this decision. When these schedules are no longer used to provide service to customers they should be canceled by SDG&E. DRA's recommendation to reflect the rate structure changes to schedules AL-TOU and A6-TOU will be adopted for establishing new real time pricing schedules.

<u>Power Factor Adjustment</u>

SDG&E is currently authorized to assess customers an extra charge if they operate equipment at a low power factor. Such equipment uses reactive power, measured in kilovars (KVARs), and requires SDG&E to install capacitors to maintain system capacity. Although SDG&E's rate schedules allow a charge of $0.21/kVAR/month when a customer's power factor is below 75% of their kilowatt demand, its electric rule 2(G) authorizes a charge for power factors below 90%.

SDG&E proposes to require customers on schedules AD, AL-TOU, A6-TOU, AE-1, R-TOU-1, R-TOU-2, and PA-T-1 with demands which have exceeded 300 kw in the last 12 months to maintain a minimum power factor of 90% at their own expense. If the customer fails to install the necessary equipment, SDG&E will install it at the customer's expense. Based on 1987 costs for this equipment, SDG&E proposes to increase the charge to $0.28/kVAR/month. SDG&E states that high reactive demands are not imposed by all customers and only customers which use kVARs should pay for kVARs.

DRA has reviewed SDG&E's requested changes to the power factor adjustment and the basis for the $0.28/kVAR/month charge and supports SDG&E's proposal. However, DRA is concerned that the treatment of the revenues from this charge was not addressed and recommends that they be considered in the current 3R's proceeding I.86-10-001.

UCAN argues that SDG&E has not provided an estimate of the revenue which its power factor charge would generate or how such revenue would be treated. UCAN recommends that SDG&E's proposal be rejected or, alternatively, any power factor revenues be tracked and used to offset expenses.

General Services states that SDG&E's proposed change in its power factor charge should be rejected. General Services makes this recommendation based on the lack of evidence to indicate there is a reactive power problem and the failure of SDG&E to estimate the amount of money the charge would generate. If a 90% power factor charge is adopted, General Services recommends that:

1. Implementation be delayed by six months to permit customers the opportunity to correct their own power factors.

2. Revenues be estimated and credited to each affected class or treated like standby revenues.

3. Customers be paid for power factors above 90%.

4. The lowest cost capacitors be used to develop a reactive charge.

SCC recommends rejection of SDG&E's power factor proposal to avoid discrimination against self-generation facilities.

We agree with SDG&E that customers with high reactive demands should pay for the kVARs they use, but SDG&E has not adequately demonstrated that it used the least cost equipment to develop its reactive charge. Without adequate support we will not increase SDG&E's present per kVAR charge.

Since most customers are not aware of SDG&E's present reactive charge, we will allow them six months to correct their power factors before being assessed the kVAR charge. To provide consistent treatment for special charges, revenues generated by the kVAR charge will be recorded in the same manner as standby revenues.

Finally, General Services has not sufficiently supported its claim that customers with high power factors benefit SDG&E's electric system. Accordingly, we will not adopt General Services recommendation that SDG&E pay customers with power factors above 90%. With the above modifications, we will adopt SDG&E's power factor proposal.

<u>Standby Service</u>

Rate schedules S and S-I provide standby service to demand-metered customers where SDG&E does not supply all or part of their regular electric requirements. These schedules were substantially modified by D.87-12-069 to reflect changes in the AL-TOU schedule. Under schedule S, 80% of the contracted maximum demand is billed at the AL-TOU non-coincident demand charge.

Schedule S-I has no associated charge, is limited to customers with demands exceeding 500 kw, and does not require SDG&E to provide service when its system is at full capacity. Under the current structure, standby customers which take energy during on-peak hours pay regular on-peak demand charges and associated energy rates, subject to a rate limiter of $0.67/kilowatt hour (kWh) in the summer and $0.26/kWh in the winter.

SDG&E believes more time is needed to acclimate customers to the present rate structure for standby service and does not recommend any changes. However, SDG&E does propose two new special conditions. First, SDG&E requests the option of providing standby service only to customers taking service through a single meter. This condition is intended to prevent arbitrage, a customer could take standby service during off-peak periods under AL-TOU and on-peak service through another meter on a different schedule. Second, SDG&E requests that standby service for customers with contract capacity exceeding 20 MW be provided by a Commission-approved contract. Such contracts, SDG&E argues, would provide the time and certainty needed to prepare for large standby service.

DRA proposes that the current rate structure be replaced by an on-going reservation charge equal to 2% of the coincident or on-peak demand charge applied to contracted standby demand. Additionally, when customers take service for forced outages, the on-peak demand charge would apply, but it would be prorated daily.

In response to DRA's proposal SDG&E argues that:

1. Prorating the on-peak standby charge does not compensate SDG&E for the cost of the facilities it must have available.

2. It is unlikely that standby customers would be able to provide same day notice of forced outages as required by DRA's proposal.

3. Standby service which is billed by hand would become more complicated.

FEA supports DRA's standby proposal, but recommends that customers only pay the greater of the prorated on-peak demand charge or the 2% reservation charge. FEA states that DRA's reservation charge is justified on the grounds that standby customers have different load characteristics than full requirements customers. FEA also contends that there should be no limitation on size regarding a cost-based standby rate and customers with multiple meters should be allowed to take standby service if all service is under one schedule.

General Services also supports DRA's proposal, but recommends four changes. First, the daily on-peak demand charge should be prorated on an hourly basis. Second, rate limiters should be retained. Third, the 2% reservation charge should be credited to any on-peak demand charges incurred during the month. Finally, AD customers should be allowed to take standby service and receive a credit for non-coincident demand charges on contracted standby load. Additionally, General Services suggests that a rate limiter be created for AD customers taking standby service.

SCC recommends that DRA's proposed standby rate structure be adopted with the retention of rate limiters and a provision for AD customers to take standby service.

IPC proposes a standby rate based on the marginal costs of facilities to serve all loads discounted to reflect the expected forced outage rate of self-generation facilities. The discount represents the probability that the standby service will be needed. This approach was developed by IPC to insure that standby customers are charged based on their use, not their potential for use.

IPC contends that a standby load can be expected to appear on the utility system randomly, during any time period and any season, and the forced outage rate measures the probability of this occurrence. IPC equates its methodology with that used to set rates for full requirements customers. Since all potential loads for full requirements customers do not occur on the utility system simultaneously, their rates are based on peak loads, which are a percentage of all potential loads. Similarly, IPC believes that standby rates should be based on forced outage rates, which are a percentage of the contracted standby loads.

IPC uses the California Energy Commission staff's forced outage rate for gas-fired cogeneration projects of 9% as representative of the self-generators in SDG&E's service territory. The 9% factor is multiplied by the adopted monthly marginal costs for generation, transmission, and distribution to derive the monthly per kw charge for standby service. The generation costs include a 15% reserve margin to reflect SDG&E's system reliability. Using the marginal costs proposed by DRA this method produces a monthly standby charge of $1.40/kw.

Under IPC's proposal standby customers would pay $1.40/kw/month whether or not service is taken. Standby customers that take service would also pay the energy charges from the rate schedule that would otherwise apply. No additional demand charges would be required, because all fixed costs that are recovered in the demand charges are included in the monthly standby rate.

<u>Discussion</u>

In D.86-12-091 for PG&E we established a policy for standby service that has been used as a guide to establish Edison's and SDG&E's current standby rates. That policy states that when standby customers take service, they impose costs in the same manner as full requirements customers, and should be charged the same rates. For periods when service is not taken, standby customers should pay the cost of customer-related services and dedicated facilities.

DRA's proposal with a 2% reservation charge is not consistent with this policy. First, the 2% charge is not related to facilities that are dedicated to standby customers. Second, when standby customers take service they would only be required to pay a daily proration of the on-peak demand charge compared to an entire month for full requirements customers. We consider it inequitable to provide standby customers with daily proration without providing it to full requirements customers.

IPC recommends a new approach for developing standby charges which, except for the concerns expressed below, appears to be a fundamentally sound methodology. As with DRA's proposal, IPC's methodology does not recognize that certain facilities are dedicated to serve standby customers and assumes that all transmission and distribution facilities are fully diversified. For generation costs which are recovered in coincident demand charges, IPC's approach indirectly results in a proration of on-peak demand charges. We believe an appropriate standby charge must address both of these concerns.

We also disagree with SDG&E's two proposed special conditions. First, customers should not be excluded from standby service because they take service from more than one meter. To avoid the possibility of arbitrage we will require that standby customers take all service under the same rate schedule. Second, SDG&E has not provided adequate justification for requiring a Commission-approved contract before customers with contract capacity exceeding 20 MW can receive standby service.

Finally, we will maintain the existing standby rate structure as the best representation of our standby policy at this time. Additionally, we see no reason why AD customers which elect standby service should be treated differently than TOU customers on standby service. Accordingly, as recommended by General Services, AD customers will be allowed to take standby service and receive a credit for non-coincident demand charges on their contracted standby load. The current standby rate limiters, which establish a ceiling for the average on-peak rates, will also apply to AD customers.

PG and PG-QF

PG-QF was designed for cogeneration customers with output of 100 kW or less. D.87-12-069 closed this schedule to new cogeneration facilities above 20 kw by June 30, 1989. PG is an experimental schedule available to customers with generation facilities connected in parallel to SDG&E's system where no other schedule is available. Customers under either schedule currently pay no standby charge and are allowed to credit excess electricity produced against consumption during other periods. Under PG-QF excess generation is purchased by SDG&E at its current standard price offer.

SDG&E recommends that as of July 1, 1989 the energy netting provision of PG be closed to all customers and the schedule be closed to new customers. SDG&E claims that the lack of standby charges and the energy netting provision allows customers on these schedules to avoid paying the full cost of service.

Since there appears to be no opposition to SDG&E's proposal we will close the PG schedule to new customers and eliminate the energy netting provision. We also reaffirm the intent of D.87-12-069 to close the PG-QF to new customers with generation facilities above 20 kW and to eliminate the energy netting provision by June 30, 1989. To provide consistent treatment for both schedules the adopted changes will become effective on June 30, 1989.

Special Contracts

The movement toward an increasingly competitive environment in the electric utility industry has generated concern over the loss of utility market share. We have addressed this concern by adopting marginal cost principles for revenue allocation and rate design. This is intended to prevent a bias for either utility or alternate energy sources. Although we have implemented marginal cost principles, our goal of marginal cost-based rates has been hampered by: (1) differences between marginal cost revenues and the utility's revenue requirement and (2) the magnitude of customer bill impacts. This has resulted in the approval of special contracts to avoid uneconomic bypass during a period of excess capacity. Rates for selected customers with special contracts have been as low as Standard Offer #1 price levels. D.88-03-008 states:

> "The term of a special contract conforming to the guidelines should not extend into any year when forecasts indicate that additional capacity will be needed to meet target reserve margins. The purpose of allowing special contracts is to take advantage of existing excess capacity. Considerable justification will be required to demonstrate the benefits of extending discounted rates into a period when increased demand creates a need for additional capacity." (P.16, D.88-03-008)

Exhibit 11, SDG&E's Report on Electric Resource Plan, December, 1987, indicates there is a clear need for new capacity beginning in 1989. This need for capacity has led IPC to recommend that: (1) SDG&E not offer rate discounts or discourage self-generation facilities and (2) the adopted rate schedules should not create economically unjustified barriers to self-generation.

We agree with IPC's position and believe our adopted rate schedules will not prevent the installation of economically justified self-generation facilities. We also share IPC's concern for special contracts and reemphasize our discussion in D.88-03-008 by the following:

1. SDG&E should not enter into special contracts which provide customers with reduced rates in a year when forecasts indicate a need for additional capacity.

2. Such contracts should include considerable justification demonstrating the benefits for all other SDG&E ratepayers.

Agricultural

DRA and SDG&E were the only parties that made agricultural rate proposals. DRA endorses SDG&E's agricultrual rate structure proposal as discussed below:

1. Maintaining the present customer charges of $8.00/month with an additional $10.00/month for TOU meters on PA-TOU schedules.
2. Maintain the 3.401:1 relationship between on- and off-peak energy rates on the PA-TOU schedule.
3. Offer schedule PA-T-1 with a $20.00/month customer charge and preserve the existing relationship between agricultural and industrial TOU demand and energy charges.
4. Eliminate the current minimum charges for agricultural schedules.

No party opposed SDG&E's recommended agricultural rate structure and the Association of California Water Agencies by letter to the ALJ supported SDG&E's proposal. We will adopt SDG&E's recommended agricultural rate proposal.

Late Payment Charge

SDG&E proposes to institute a late payment charge of 1.5% on all non-residential bills not paid within 25 days of the billing date. The City of San Diego recommends that the interest rate for the late payment charge be limited to SDG&E's balancing account rate. General Services objects to imposition of a late penalty charge against governmental facilities, the level of the charge, and the time allowed for payment of the charge. According to General Services, Government Code Section 926.17(b)(1) limits the amount of interest governmental facilities can be charged to 1% above the Pooled Money Investment Account, but not to exceed 15%. Additionally, General Services suggests that the time allowed for payment of the bill without penalty should be 50 days from the postmark date of mailing.

We will authorize SDG&E to establish a late payment charge for non-residential customers. The charge will only apply to balances that have not been paid within 30 days from the billing date. The monthly late payment charge should be calculated by dividing SDG&E's authorized return on rate base by 12 and rounding the quotient to the nearest one tenth of one percent. In no event should governmental facilities be charged a late payment fee that exceeds the amount authorized by the Government Code.

SDG&E should not implement the late payment fee until March 1, 1989. This should provide adequate time for SDG&E to notify customers of the new charge and allow them to adjust their payment procedures, if warranted.

Street Lighting

SDG&E, DRA, California City-County Street Light Association (CAL-SLA), and the City of San Diego actively participated in this part of the proceeding. Street lighting rates are developed in two steps. Revenues are first allocated to the street lighting class. The class revenues are then used to determine individual rate schedules. The issues concerning this process are discussed below.

Revenue Allocation

All parties except SDG&E recommend a full EPMC revenue allocation, excluding facilities charges. Facilities charges are costs associated with end-use equipment, lamp poles, luminaires, etc. Facilities charges are typically removed from marginal cost revenue allocation methodologies because utilities do not provide end-use equipment to all classes.

SDG&E proposes that SAPC be used to allocate revenues to the street lighting class. SDG&E based its proposal on the following:

1. SAPC was used in its 1987 ECAC decision, D.87-12-069.

2. D.85-12-108, SDG&E's last general rate case decision, stated that the street lighting class should not experience a rate increase if the class revenues are in excess of marginal costs.

3. Current methodologies for determining street lighting marginal costs are not reliable.

Although DRA and CAL-SLA recommend the use of full EPMC, excluding facilities charges, CAL-SLA believes that DRA's marginal demand costs are too high. Since DRA and CAL-SLA propose similar revenues for marginal energy and customer costs, similar facilities charges, and similar EPMC multipliers, this represents their only difference for revenue allocation. The City of San Diego supports CAL-SLA's position.

CAL-SLA uses SDG&E's demand allocation factors which it believes accurately measure the demand street lights place on SDG&E's electric system. DRA uses coincident and non-coincident demands and estimates substation loadings as a function of total system demands to develop its allocation factors. This methodology assumes the maximum non-coincident demand billing determinants are equal to the sum of individual maximum demands for the class and determines coincident demands using LOLP-weightings which is consistent with DRA's methodology for other customer classes.

CAL-SLA argues that DRA's demand allocation process is inappropriate for street lighting because:

1. There is no need to estimate substation loadings since SDG&E presents loadings developed from load research.

2. There is no difference between maximum demand for the street lighting class and the sum of maximum demands for individual customers. All street lights come on and go off at the same time.

3. The load curve for the street lighting class is flat.

We will adopt DRA's revenue allocation methodology for street lighting, since it determines maximum demands from the sum of individual demands and is consistent with the revenue allocation methodology adopted for other customer classes.

Rate Design

SDG&E proposes that changes for individual street lighting rates be limited to plus or minus 5% from SAPC. In response to concerns for unbundled street lighting rates, SDG&E also developed an unbundled EPMC street lighting rate design. Additionally, SDG&E proposes a $6.00/pole/year attachment fee for LS-2 customers. SDG&E's pole attachment fee is based on an agreement it reached with the City of San Diego. Finally, SDG&E proposes that joint ownership of lighting facilities be eliminated and a service fee for de-energizing lights for non-payment be approved.

CAL-SLA states that there are inconsistencies in SDG&E's proposed EPMC rate design, which result in intra-class subsidization without economic justification. Accordingly, CAL-SLA recommends its unbundled rate design which focuses on the cost components that provide information on which service to purchase. CAL-SLA also objects to SDG&E's requested pole attachment fee arguing that:

1. Revenues are already collected to compensate for the space on distribution poles.
2. The proposed fee is not cost-based.
3. No estimate of pole attachment fee revenues was made.
4. Pole attachment fees were not reflected in miscellaneous revenues.
5. LS-2 customers would have to pay twice to amortize distribution poles.

DRA accepts the pole attachment fee negotiated by SDG&E and the City of San Diego and agrees with SDG&E's proposed elimination of jointly owned equipment.

Obviously, there is some benefit being derived from the use of SDG&E's poles for attaching street lights and cable television wires. If this benefit accrued to all SDG&E ratepayers there would be no need establish a pole attachment fee. Since all SDG&E ratepayers are not likely to be cable television subscribers, it is clear that all SDG&E ratepayers do not share in the benefits from attaching cable television wires to SDG&E's poles. Accordingly, we support the current policy of assessing pole attachment fees to cable television companies with the benefits passed on directly to all ratepayers.

In contrast to cable television wires, street lights generally benefit all SDG&E ratepayers. Street lights provide security and increased safety for the public by lighting streets, sidewalks, and other property. Because these benefits accrue to society as a whole and SDG&E ratepayers in particular, we conclude that there is no need for a pole attachment fee for street lights.

Finally, we will adopt CAL-SLA's EPMC unbundled rate design because it focuses on the cost components that provide information on which service to purchase.

<u>Gas Rate Design</u>

Gas marginal costs, cost allocation, and rate design are not addressed in this proceeding because the structure of gas rates was determined by D.86-12-010, D.86-12-009, and D.87-12-039. These decisions adopted a rate structure which is not subject to change for two years. Accordingly, SDG&E states that the only issues to be addressed are:

1. When SDG&E's authorized change in gas margin can be reflected in rates.

2. Baseline allowances.

3. Master meter unit discounts.

SDG&E points out that the agreement adopted by D.87-12-039 does not require all gas rate adjustments to be coincident with ACAP. Based on this interpretation, SDG&E requests that changes in its gas margin not be delayed until ACAP which has a scheduled effective date of July 1, 1989. DRA reads D.87-12-039 to limit rate changes to ACAP proceedings for two years.

Without a rate revision prior to ACAP, the margin change allocable to core customers would be placed in a balancing account, while the margin change allocable to non-core customers would not be recoverable. This discrepancy between customer groups is caused by the elimination of the supply adjustment balancing account for non-core customers. Margin recovery for non-core is now authorized prospectively.

To provide equitable treatment, we will authorize SDG&E to revise non-core rates, effective January 1, 1989. The revised non-core rates should reflect the change in margin adopted in this decision, but in all other respects the current revenue allocation and rate design methodology should remain unchanged. Since there is a balancing account for core customers, there is no compelling reason to reflect the increase authorized by this decision in rates at this time. We will adopt DRA's recommendation and not revise core customer rates until SDG&E's ACAP proceeding. Our adopted gas rates for non-core customers are shown in Appendix G.

This leads to a problem that exists with the level of detail contained in the Stipulation and Agreement adopted by D.88-09-063. To allocate costs between core and non-core customers specific detail for key cost data is required. D.88-09-063 combined with this decision set the level of costs to be used for revenue allocation in SDG&E's ACAP proceeding. Since the necessary level of detail for these costs is deficient, we will direct DRA and SDG&E to conduct workshops with the signatories to the Stipulation and Agreement. These workshops should identify the cost detail required for revenue allocation in SDG&E's ACAP proceeding. The results of these workshops should be served on all parties to this proceeding and SDG&E's last consolidated adjustment mechanism proceeding prior to SDG&E's ACAP filing.

Consistent with its recommendation for electric baseline allowances, DRA recommends that gas baseline allowances which conform with PU § 739 continue to be phased-in. SDG&E argues that changes in baseline allowances will create an upward pressure on residential bills and, if changes are adopted, they should not be implemented until May 1, 1989, when seasonal baseline changes occur.

As with electric baseline allowances, we agree with DRA that continued phase-in of gas baseline allowances meets the requirements of PU § 739 and will adopt its recommendation. Baseline allowances for gas customers will be reduced over a one to three year period starting May 1, 1989. The adopted baseline allowances are shown in Appendix G.

SDG&E, WMA, and DRA have agreed that the discount for mobilehome parks on schedule GT should be $6/unit/month or $0.197/unit/day. For apartment buildings on schedule GS, no party opposes SDG&E's proposed discount of $1.90/unit/month or $0.062/unit/day. These discounts appear reasonable and will be adopted.

<u>Steam Rate Design</u>

SDG&E provides steam service under two rate schedules which are closed to new customers. SDG&E's two steam schedules (1 and 2) differ only in that schedule 2 has one percent higher rates than schedule 1 to reflect an additional franchise fee requirement. Both consist of a service charge and a commodity charge per 1,000 pounds of steam provided.

SDG&E proposes that the service charge for each schedule be doubled to allow it to recover about 50% of its service costs. The schedule 1 customer charge would be $30.00/month and the schedule 2 customer charge would be $30.30/month. The commodity charge would recover the remaining revenue requirement. DRA agrees with SDG&E's proposal and notes that SDG&E's remaining steam customers have been notified of the proposed increases, but have made no response. We will adopt SDG&E's proposed rate changes for its steam schedules, as reflected in Appendix H.

Intervenor Funding

Pursuant to the Commission's Rules of Practice and Procedure Rule 76.54, Public Advocates, UCAN, CPIL, and Rate Watchers have filed requests for a finding of eligibility for compensation under Rule 76.56. Additionally, UCAN, CPIL, and Rate Watchers have filed requests for compensation. We will discuss each of these requests below.

Public Advocates

Public Advocates filed a request for finding of eligibility of attorneys' fees and other reasonable costs restricted to the issue of W/MBE contracts. Public Advocates states that it represents the following non-profit organizations on W/MBE issues: American G.I. Forum, League of United Latin American Citizens, and Filipino American Political Association. These organizations have annual budgets ranging from $25,000 to $50,000 with the majority of funds going to education. All officers of the organizations are volunteers and there are no salaries or legal expenses.

Additionally, Public Advocates indicates that individual members of the organizations are SDG&E ratepayers and it is impractical and economically infeasible for individual minority and female ratepayers to represent their interests adequately before the Commission. Moreover, none of the organizations involved has a financial benefit at stake. The benefit will go to those businesses and individuals who contract their services to utilities. Although the organizations may receive some benefit through the improved efficiency of SDG&E, this would be common to all ratepayers and certainly not significant compared to the cost of representing W/MBE interests. Public Advocates estimates that its cost of participation will be approximately $6,000.

Finally, Public advocates argues that it has: (1) diligently and efficiently pursued the issue affecting minority and women-owned businesses, (2) particular expertise in the field of W/MBE contracts, and (3) been involved with representing W/MBE rights in numerous ratemaking proceedings.

We conclude from Public Advocates' filing that: (1) it represents an interest necessary for a fair determination of the proceeding, which is not otherwise adequately represented, (2) the economic interest of the individual members of the organizations it represents is small in comparison to the cost of effective participation, and (3) it is eligible for compensation under Rule 76.54.

UCAN

UCAN states it was previously found eligible for compensation by D.88-03-023, which satisfies the requirement for financial hardship under Rule 76.54. Additionally, UCAN has provided an estimate of its cost of participation and a statement of the issues it addressed in the proceeding. Based on UCAN's filing and D.88-03-023 we conclude that UCAN is eligible for compensation.

UCAN has also requested intervenor compensation in the amount of $77,067. Of the requested amount, $25,000 is associated with the Stipulation and Agreement adopted by D.88-09-063 with the remainder for issues involving marginal cost, revenue allocation, rate design, and depreciation. The following is a summary of UCAN's request:

Stipulation and Agreement Issues

Attorney Fees & Expenses

Demand Side Management (42.3 hours)	
Procedural Issues (39.9 hours)	
Rate Base & Working Cash (24.85 hours)	
Settlement Conferences (23.1 hours)	
Total Attorney Fees @ $125/hour	$16,269
Air Travel ($927)	
Hotel & Meals ($244)	
Parking ($62)	
Copying, Telephone, Postage, & Misc. ($1,668)	
Total Expenses	$2,901
Total Attorney Fees & Expenses	$19,170

Expert Costs

Demand Side Management	$7,000
88 hours @ $50/hour	
Expert Assistance Review ($2,000)	
Secretarial Support 50 hours @ $12/hour	
Rate Base & Working Cash	$2,141
35.8 hours @ $55/hour	
5 hours @ $35/hour	
Other Results of Operation Issues	$3,930
44.3 hours @ $55/hour	
24.5 hours @ $45/hour	
11.3 hours @ $35/hour	
Review of Operation & Maintenance	$900
6 hours @ $150/hour	
Copying, Telephone, Postage, & Misc.	$650
Total Expert Fees & Expenses	$14,621*
Total Fees & Expenses	$33,791*
Total Stipulation and Agreement Compensation Request	$25,000

* Corrected for Calculation Errors

Contested Matters

Attorney Fees & Expenses

Marginal Cost (72.2 hours)
Rate Design (82.25 hours)
Depreciation (20.25 hours)
Revenue Allocation (9.5 hours)
Resource Planning (5.0 hours)
Marginal Cost & Rate Design Unallocable (18.25 hours)
Preparation of Brief (68.3 hours)
Preparation of Compensation Request (13.7 hours)

Total Attorney Fees @ $125/hour	$36,181

Air Travel ($824)
Hotel & Meals ($167)
Parking ($44)
Copying, Telephone, Postage, & Misc. ($1,691)

Total Expenses	$2,726
Total Attorney Fees & Expenses	$38,907

Expert Costs

Marginal Costs
94 hours @ $55/hour
18.2 hours @ $45/hour
14.3 hours @ $35/hour
Rate Design
32.8 hours @ $55/hour
3.2 hours @ $45/hour
12.5 hours @ $35/hour
Revenue Allocation
39.6 hours @ $55/hour
1.7 hours @ $45/hour
1.5 hours @ $35/hour
Depreciation 9.5 hours @ $55/hour

Copying, Telephone, Postage, & Misc.	$1,055
Total Expert Fees & Expenses	$13,159
Total Contested Matters Compensation Request	$52,067

UCAN requests compensation for its work in demand-side management, rate base, working cash, settlement conferences, and procedural matters. Although these issues are part of the Stipulation and Agreement adopted by D.88-09-063, UCAN states that it made a substantial contribution to the decision.

For demand-side management UCAN points out that it submitted a 97 page report and that many of its recommendations were agreed to by DRA and SDG&E. UCAN also submitted a 127 page report on rate base and working cash and argues that its contribution to these issues, although not expressly acknowledged on the record, was substantial and compensable. Finally, UCAN was involved in a number public hearings, workshops, and settlement conferences for which it requests compensation and cites D.87-07-033 as precedent when the informality of a proceeding prevents precise assignment of contribution.

We agree with UCAN that it would be inappropriate to encourage intervenor participation in workshops and settlement conferences and deny compensation because there is no clear assignment of contribution. In this proceeding we are persuaded that UCAN was not only a signatory to the Stipulation and Agreement, but actively participated in the settlement process. We also recognize that UCAN has made a sincere effort by only requesting compensation for 74% of its total expenses related to the Stipulation and Agreement. Accordingly, we will award UCAN $25,000 for its contribution to the Stipulation and Agreement adopted in D.88-09-063.

As discussed in the marginal cost section of this decision UCAN made a number of recommendations that resulted in a substantial contribution to this decision, especially for directly assignable and customer accounting costs. In contrast, UCAN's recommendations for common distribution costs and its incremental/decremental methodology for marginal customer costs were not adopted. After weighting the issues on which UCAN prevailed versus those on which it did not, we conclude that UCAN should be compensated for 50% of its marginal cost request.

UCAN's opposition to SDG&E's proposals to impose late charges, telephone collection charges, and an increase in returned check charges on residential customers appears to have significantly influenced SDG&E's decision to drop the first two proposals. UCAN was the only party to actively oppose the returned check charge increase and clearly contributed to our denial of SDG&E's request. While UCAN participated in a number of other rate design issues, as detailed in the rate design discussion, its contribution did not substantially impact their final resolution. We conclude that UCAN should be awarded 25% of its request for its contribution to rate design issues.

For revenue allocation we adopted DRA's methodology and will not grant UCAN's requested compensation for this issue.

Finally, UCAN's recommendation concerning three life lengthening maintenance programs was adopted. This is discussed in the section on depreciation. Accordingly, UCAN will be provided 100% of its request for depreciation.

UCAN's total request for issues not related to the Stipulation and Agreement is $52,067. Based on the foregoing discussion we will award UCAN $19,907 for its contribution to this decision. Direct expenses and unallocable costs were prorated to conform with our discussion and UCAN's recommended allocation for briefing and petitioning costs: marginal cost 55%, revenue allocation 25%, rate design 10%, depreciation 5%, and other 5%. This is consistent with our treatment of out-of-pocket expenses in D.88-08-055. Since D.88-03-023 found UCAN's $125/hour rate for attorney fees reasonable, we have adopted it for this decision.

<u>CPIL</u>

On August 4, 1988 CPIL filed a request that it be found eligible for compensation and awarded $7,569. Additionally, CPIL moves that its request for a finding of eligibility be deemed timely filed under Rule 76.54(c).

Under Rule 76.54(a) a request for finding of eligibility for compensation must be filed within 30 days of the first prehearing conference, or within 45 days after the close of the evidentiary record. CPIL argues that its entry into this proceeding was for a limited purpose which occurred while the opening window was closed.

Although CPIL's participation began late in the proceeding, it was not precluded from filing a request for eligibility within 45 days after the close of the evidentiary record. Instead CPIL filed between the two windows. We realize that it is often difficult to precisely follow the rules governing intervenor compensation requests. It is not the intent of these rules to limit intervenor participation, but to provide an orderly process for requesting compensation. Since CPIL has made a reasonable effort to conform to these rules, its filing will be considered timely.

CPIL is a non-profit public interest group which represents the interest of customers who would have been subject to SDG&E's customer charge when service is temporarily disconnected. CPIL represents the interests of the unorganized and underrepresented in State regulatory proceedings, provides an academic center of learning in administrative law, and teaches direct clinic skills in public interest regulatory law. CPIL obtains financial support through grants, subscriptions to the California Regulatory Law Reporter, and legal advocate fees.

CPIL states that the customers that would have been impacted by SDG&E's proposed charge are not adequately represented by any other party and their individual economic interest is small. SDG&E estimated that its proposed charge of $4.80/month for each month service is temporarily disconnected would generate $50,000 from 2000 customers. CPIL argues that this could hardly support intervention by individual customers and that CPIL's cost of $7,569 was cost-effective for the affected customers. Based on CPIL's representations we agree that it has met the requirements of Rule 76.54 and should be found eligible for compensation.

The following is a summary of CPIL's compensation request:

<u>Attorney Fees & Expenses</u>

8.1 hours @ $200/hour	$1,620
30.3 hours @ $125/hour	$3,781
55.5 hours @ $30/hour	$1,665
Postage	$503
Total Compensation Request	$7,569

CPIL's requested award is for the preparation of testimony, its compensation request, and participation during the proceeding. Through its testimony and participation CPIL claims to have made a substantial contribution to D.88-07-023. Although SDG&E withdrew its proposal to require residential customers to pay a reconnection charge for the period when service is disconnected, CPIL argues that SDG&E's withdrawal was in the face of CPIL's opposition. Additionally, CPIL states that D.88-07-023 confirmed CPIL's position opposing SDG&E's proposed charge.

SDG&E is opposed to CPIL's intervenor compensation request stating that CPIL did not make a significant contribution to D.88-07-023 and did not provide sufficient detail of its services and expenses.

A superficial look at D.88-07-023 might lead SDG&E to conclude that CPIL did not contribute to the decision. In D.88-07-023 we credit CPIL for its opposition to SDG&E's proposed charge, otherwise, the decision is silent with respect to SDG&E's proposal. There are two reasons for this. First, SDG&E withdrew its proposal. Second, the elimination of the customer charge for all residential customers made SDG&E's proposal moot.

In this proceeding SDG&E presented a number of controversial proposals that were eventually withdrawn. While SDG&E should be commended for its willingness to rethink positions, this approach could cause intervenors to spend their limited resources without compensation. Fortunately, CPIL was the only party to aggressively oppose SDG&E's proposal. From this we conclude that withdrawal of the proposal was substantially influenced by CPIL's participation in the proceeding and that CPIL should be compensated for its effort.

Although CPIL should be awarded compensation, we are not satisfied with the description of services and expenditures it provided. Rule 76.56 requires that a claimant submit a detailed description of services and expenditures. A summary of total hours by individual does not meet this requirement. CPIL should have provided a precise description of the activities performed and the amount of time each person devoted to each activity.

Additionally, our review of UCAN's compensation request, which provides considerable detail, indicates CPIL's request is excessively high in relation to the complexity and the limited litigation of the issue. For example, both revenue allocation and depreciation issues were far more complex and extensively litigated, but UCAN's combined costs for these issues is less than $10,000. Accordingly, we will award CPIL 50% of its request as reasonable compensation.

Finally, we are not satisfied with CPIL's basis for charging $200/hour for Robert Fellmeth's legal work. CPIL's sole reason for increasing Robert Fellmeth's $150 hourly rate, adopted in D.87-05-030, was that his current rate is $200/hour. Without adequate justification for an increase, we will use $150/hour as Robert Fellmeth's hourly rate. This rate is consistent with the hourly rates we have adopted in recent intervenor compensation awards and CIPL's request for sanctions in I.88-08-046.

The above adjustments to CPIL's compensation request result in an award of $3,582.

Rate Watchers

Rate Watchers is a newly formed advocacy group of SDG&E ratepayers which on August 18, 1988 filed a request for a finding of eligibility for compensation and an award of $5,163. Rate Watchers states that it receives no grants, is supported only by the limited resources of its members and claims the economic interests of its individual members is small in comparison to the cost of participation.

As with CPIL, Rate Watchers filed it request for finding of eligibility more than 30 days after the first prehearing conference and prior to 45 days from the close of the evidentiary record. Consistent with our treatment of CPIL's request, we will consider Rate Watchers' eligibility request to be timely filed. However, in future proceedings we suggest that Rate Watchers file eligibility requests within 30 days of the first prehearing conference. This procedure would allow us to point out similar positions of other parties, areas of potential duplication, and unrealistic expectations for compensation.

The following is a summary of Rate Watchers compensation request:

<u>Expert Costs</u>

Parade Activities	$580
20 hours @ $22/hour	
2 hours @ $55/hour	
3 hours @ $10/hour	
Public Hearings Participation	$2,156
28 hours @ $22/hour	
28 hours @ $55/hour	
Preparation for Evidentiary Hearings	$121
3 hours @ $22/hour	
1 hour @ $55/hour	
Attend Evidentiary Hearings	$1,320
24 hours @ $55/hour	
Comments on Interim Order	$265
4 hours @ $45/hour	
1 hour @ $55/hour	
3 hours @ $10/hour	
Postage & Misc. Office Supplies	$75
Telephone	$135
Transportation	$61
Parking	$40
Printed Flyers	$210
Stickers & Signs	$106
Bullhorn Rental	$94
Total Compensation Request	$5,163

D.88-07-023 repealed the $4.80 customer charge for residential customers and reestablished the $5.00 minimum bill. Rate Watchers asserts that it substantially contributed to that decision through organizing a prehearing parade and demonstration, and other activities intended to increase the extent of opposition to the customer charge expressed at the public hearings. Rate Watchers also claims responsibility for providing witnesses and evidence from which D.88-07-023 concluded a climate of distrust and perceived unfairness contributed to the lack of customer understanding of the customer charge. While UCAN and CPIL and DRA represented the interest of residential ratepayers, only Rate

Watchers adequately represented the narrow issue of the customer charge impact on customers.

SDG&E opposes Rate Watchers request for compensation on the basis that Rate Watchers activities are not compensable.

Rate Watchers' participation in the public and evidentiary hearings clearly defined the scope of customer dissatisfaction with SDG&E's customer charge and contributed to its repeal in D.88-07-023. Although we conclude that Rate Watchers should be awarded compensation, a considerable amount or their request is not compensable. Rate Watchers will only be awarded compensation for its participation in the public and evidentiary hearings, and comments on the ALJ's proposed decision relating to the customer charge. Additionally, we will reduce the number of hours for public hearings by half to reflect the actual amount of hearing time. We will not award compensation for parade activities, printed flyers, stickers, signs, and bullhorn rental.

Finally, we believe the level of regulatory expertise exhibited by Rate Watchers to be comparable to that of CPIL's law clerks and paralegals. Accordingly we will limit Rate Watchers' hourly rate to that charged by CPIL for similar regulatory expertise, $30/hour.

The above adjustments result in a total compensation award for Rate Watchers of $2,038.

Findings of Fact

1. On December 1, 1987 SDG&E filed A.87-12-003 requesting authority to reduce rates for its electric department and increase rates for its gas and steam departments for test year 1989.

2. SDG&E's A.87-12-003 requests attrition increases in 1990 and 1991.

3. Two days of public participation hearings were held in March, 1988 and 21 days of evidentiary hearings were held between April and September, 1988.

4. Except for depreciation and cost of capital, revenue requirements items normally litigated in SDG&E's general rate proceeding were agreed to in a Stipulation and Agreement and adopted in D.88-09-063.

5. Cost of capital issues were bifurcated and consolidated with other energy utilities in a generic cost of capital proceeding.

6. D.88-09-063 provided for revisions to the adopted Stipulation and Agreement for NRC fees, labor and non-labor escalation rates, EPRI dues, and W/MBE program costs.

7. SDG&E submitted a reliability of service study in compliance with D.87-12-069.

8. SDG&E, PG&E, and Edison expect to submit a comparison of rates study by June 1, 1989.

9. SDG&E estimates that as of December 31, 1988 CLMAC will have overcollected electric revenues by $10.7 million and gas revenues by $3.6 million.

10. DRA's Standard Practice U-4 has consistently been adopted for ratemaking depreciation.

11. U-4 provides a formalization of the theory of depreciation and guidelines for performing the statistical analyses on which depreciation computations are based.

12. U-4's remaining life methodology recovers the original cost of depreciable fixed capital less net salvage value over the useful life of the asset.

13. SDG&E proposes that the remaining lives for 17 electric department plant accounts be adjusted by using a method referred to as QAU.

14. SDG&E has included in its requested level of O&M expense three programs, wood pole treatment, underground switch maintenance, and padmount transformer painting, that are expected to extend the lives of various plant and equipment.

15. SDG&E's QAU methodology only considers life shortening uncertainties.

16. SDG&E has not provided the support for the assumptions developed from its QAU interviews.

17. U-4 methodology can increase or decrease the average remaining lives of plant accounts to reflect past and expected retirements.

18. Depreciation analysts use judgment in the development of average remaining plant lives.

19. Mortality and other historic data are the primary inputs used for the development of average remaining lives.

20. U-4 does not limit depreciation analysts to the use of historical data, information on product life from manufacturers or known changes in plant can also be used to develop average remaining lives.

21. FCC represcribes depreciation rates at three-year intervals for telecommunication utilities.

22. Under FCC's represcription procedure a telecommunication utility submits proposed changes in depreciation to DRA and FCC staff, DRA and FCC staff develop recommendations, and areas of disagreement are discussed in a joint meeting with all three.

23. Depreciation rates for energy utilities are determined on a three-year cycle in general rate proceedings.

24. D.84-06-111 adopted technical updates for Pacific Bell that provide for automatic adjustment of depreciation rates to account for changes in the composition of utility plant and relative growth or decline in depreciation reserve.

25. G.O. 156 requires SDG&E to participate in a clearinghouse for verification of W/MBEs.

26. The Stipulation and Agreement adopted in D.88-09-063 provides for increased W/MBE funding up to $200,000 for additional W/MBE activities such as a clearinghouse for W/MBEs.

40. UCAN's weighting of single-family and multi-family units is based on the weighting of incremental customers.

41. SDG&E did not provide an explanation for the difference between its labor overhead rate of 129% for meter installations and its 111% labor overhead rate used on work orders for customer costs.

42. SDG&E's estimate of transformer costs was developed from a moving average inventory price.

43. UCAN's estimate of transformer costs was based on the incremental cost of SDG&E's transformer purchase contracts.

44. To annualize TSM investments, UCAN excluded three FERC accounts that it felt were not related to TSM investments from SDG&E's real fixed rate.

45. DRA's real fixed rate for annualizing TSM costs was calculated using the same method as UCAN, but only two FERC accounts were excluded. The third account, which relates to protective devices and capacitors, DRA believes is associated with TSM investments.

46. SDG&E's common distribution cost methodology uses a proxy for the minimum distribution system to represent common distribution costs which are dedicated to the service of customers as distinguished from meeting their demands.

47. DRA's common distribution cost methodology identifies specific equipment as access related and assigns the investment costs directly to the appropriate customer class.

48. SDG&E has corrected its customer accounting costs for inconsistencies between its marginal cost calculation and its results of operation calculation.

49. SDG&E did not reflect differences in the cost of reading meters in its customer accounting costs.

50. SDG&E included conservation expenses in its customer accounting costs.

51. UCAN's incremental/decremental methodology reflects a hookup charge for new customers and decremental costs for existing customers.

52. UCAN's incremental/decremental methodology assumes that competitive providers of access equipment would be able to undercut SDG&E's investment costs by 75%.

53. DRA's market rental approach for marginal customer costs assumes that customers rent access equipment. Where customer ownership of access equipment exists customers are excluded from the allocation process.

54. SDG&E agreed to DRA's marginal energy revenues prior to revision for a revenue-related tax factor which was inadvertently omitted.

55. DRA calculated generation demand for test year 1989 at 1992 MW using LOLP-weighted demands.

56. Recorded 1986 generation demand was 2376 MW.

57. SDG&E, UCAN, and FEA used DRA's methodology for the calculation of distribution demand.

58. DRA's weighting factors for calculating distribution and transmission demands are consistent with its demand determinants.

59. DRA assumed that on average 20 customers are connected to each residential transformer and that no more than 25% of the maximum load of all individual customers connected to any residential transformer will occur at the same time.

60. SDG&E's distribution planning manual instructs planning engineers to use a diversity factor between 55% and 75% when 10 customers are connected to one transformer.

61. SDG&E did not provide supporting data for the average number of residential customers connected to each transformer, but argues that less than 10 are likely to be connected to a new transformer.

62. Full EPMC revenue allocation is consistent with our general policy of marginal cost-based rates.

63. Most customer classes under full EPMC revenue allocation receive decreases within plus or minus 4% of SAPC, with the largest decrease to the agricultural class, 18%, and the smallest to the residential class, 6%.

64. D.88-07-023 replaced the $4.80/month residential customer charge with a $5.00/month minimum bill.

65. D.88-10-062 addresses the realignment of baseline and nonbaseline rates in compliance with SB 987.

66. D.85-12-108 in SDG&E's last general rate proceeding adopted a phase-in of baseline allowances.

67. Some SDG&E gas and electric baseline allowances are not in conformance with PU § 739.

68. SDG&E failed to provide convincing testimony that it is unable to negotiate lower bank fees for returned checks.

69. SDG&E, WMA, and DRA agree that the mobilehome park discount should be $9.50/unit/month on schedule DT and $6.00/unit/month on schedule GT, to be prorated and billed on a daily basis.

70. SDG&E and DRA agree that the discount for apartment buildings should be $4.04/unit/month on schedule DS and $1.90 on schedule GS, to be prorated and billed on a daily basis.

71. SDG&E, DRA, and UCAN agree on the design of residential TOU schedules.

72. SDG&E withdrew the following residential rate design proposals: (1) late payment charge, (2) telephone charge with respect to bill collections, (3) customer charge, and (4) reconnection charge for the period when service is disconnected.

73. SDG&E proposes a two tiered declining block energy rate for schedule AD.

74. The schedule AD demand charge is below SDG&E's marginal capacity cost.

75. SDG&E's witness testified that it was reasonable to provide a TOU option to schedule A and AD customers.

76. D.87-12-069 in SDG&E's 1987 ECAC proceeding adopted major changes for schedules AL-TOU and A6-TOU. These changes provide for higher demand charges and lower energy rates.

77. Marginal capacity costs in this proceeding are less than those used to design the AL-TOU and A6-TOU schedules adopted in D.87-12-069.

78. SDG&E and DRA have addressed Poway's concerns for the start of the on-peak period for TOU schedules in A.88-07-003.

79. Schedules AO-TOU and A06-TOU are optional rate schedules which were closed to new customers as of July 1, 1988. No party opposed SDG&E's recommendation to maintain demand charges at their existing level and decrease all energy charges by an equal percent.

80. Interruptible service schedules do not reflect the changes in the AL-TOU demand structure adopted in D.87-12-069.

81. Coincident demand charges on schedule AL-TOU may contain more than coincident capacity costs.

82. Schedules AE-1, R-TOU-1, and R-TOU-2 are experimental real time pricing schedules which are optional for AL-TOU and A6-TOU customers, terminate on January 1, 1992, and provide for a 12-month termination notice.

83. SDG&E's AE-1, R-TOU-1 and R-TOU-2 schedules do not reflect the changes to schedules AL-TOU and A6-TOU adopted in D.87-12-069.

84. SDG&E's electric rule 2(G) authorizes a charge for power factors below 90% of their kilowatt demand. SDG&E's present rate authorizes it to charge $0.21/KVAR/month when a customer's power factor is below 75%.

85. Customers which have low power factors cause SDG&E to install capacitors to maintain system capacity.

86. Standby customers which take service under more than one rate schedule could bypass certain rates by taking service under one schedule during on-peak periods and a different schedule during off-peak periods.

87. SDG&E has not provided adequate justification for requiring a Commission-approved contract before customers with contract capacity exceeding 20 MW can receive standby service.

88. SDG&E's current standby rate structure was designed to be consistent with our standby policy adopted in D.86-12-091.

89. No party has demonstrated a need to change the standby policy adopted in D.86-12-091.

90. SDG&E's standby rate schedule requires customers to pay a non-coincident demand charge based on 80% of their contract load.

91. Schedule AD customers pay a combined coincident and non-coincident demand charge.

92. PG is an experimental schedule for customers with generation facilities. This schedule has no standby charge and customers are allowed to credit excess electricity produced against consumption during other periods.

93. Schedule PG does not recover SDG&E's full cost of service because of the lack of standby charges and the energy netting provision.

94.. D.87-12-069 closed schedule PG-QF to new cogeneration facilities above 20 kw by June 30, 1989.

95. DRA and the Association of California Water Agencies support SDG&E's agricultural proposal as described in the rate design section of this decision.

96. Costs associated with late payments by non-residential customers are paid by all customers.

97. SDG&E's Report on Electric Resource Plan, December, 1987, indicates there is a clear need for new capacity beginning in 1989.

98. DRA's full EPMC revenue allocation methodology for the street lighting class determines maximum demands from the sum of individual demands and is consistent with the revenue allocation methodology used for other customer classes.

99. CAL-SLA's EPMC unbundled street light rate design focuses on the cost components that provide information on which services to purchase.

100. Gas marginal costs, cost allocation, and rate design are not addressed in this proceeding because the structure of gas rates was determined by D.86-12-010, D.86-12-009, and D.87-12-039. These decisions adopted a rate structure that is not subject to change for two years.

101. Margin rate changes for core gas customers are subject to balancing account treatment.

102. Margin recovery for non-core gas customers is authorized prospectively and not subject to balancing account treatment.

103. Adequate detail of the costs necessary for revenue allocation in SDG&E's ACAP was not provided in the Stipulation and Agreement adopted in D.88-09-063.

104. DRA supports SDG&E's steam rate design proposal.

105. Public Advocates, UCAN, CPIL, and Rate Watchers request a finding of eligibility for compensation pursuant to Rule 76.54.

106. Public Advocates, UCAN, CPIL, and Rate Watchers each: (1) participated in one or more issues that was otherwise not adequately represented, (2) represented organizations or SDG&E ratepayers which have an economic interest that is small in comparison to the cost of effective participation, and (3) would experience financial hardship for their cost of participation without an award.

107. UCAN is a signatory to the Stipulation and Agreement adopted in D.88-09-063 and only requests compensation for 74% of its total expenses related to the Stipulation and Agreement.

108. UCAN made a number of recommendations that resulted in a substantial contribution to the marginal cost section of this decision.

109. UCAN did not significantly contribute to the adopted revenue allocation methodology, but its recommendation concerning three life lengthening maintenance programs was adopted for depreciation expense.

110. Some of UCAN's rate design proposals contributed to this decision.

111. CPIL substantially influenced SDG&E's withdrawal of the proposal to require residential customers to pay a reconnection charge for the period when service is disconnected.

112. CPIL did not submit a detailed description of services and expenditures and did not adequately justify increasing Robert Fellmeth's hourly rate for legal work from $150 to $200.

113. UCAN's combined compensation request for revenue allocation and depreciation, which were each more complex than the issue CPIL addressed, was less than $10,000 as compared to CPIL's request of $7,569.

114. Rate Watchers' participation in the public and evidentiary hearings clearly defined the scope of customer dissatisfaction with SDG&E's customer charge and contributed to its appeal.

115. A considerable amount of Rate Watchers' request is not compensable.

116. The level of regulatory expertise exhibited by Rate Watchers is comparable to that of CPIL's law clerks and paralegals.

<u>Conclusions of Law</u>

1. D.88-09-063 should be revised to reflect changes in NRC fees, labor and non-labor escalation rates, EPRI dues, and W/MBE program costs.

2. Consistent with its rate case cycle SDG&E's estimate of CLMAC overcollections should be amortized over three years.

3. In its 1990 attrition year filing SDG&E should amortize any difference between the estimated and actual CLMAC balance over two years.

4. SDG&E's QAU methodology expands the depreciation analysts's use of judgment.

5. Depreciation analysts should clearly identify all information that adjusts average remaining plant lives and the source of the information.

6. Depreciation analysts should detail the weight given to each event and how it impacts the calculation of average remaining plant lives.

7. SDG&E's QAU methodology was only designed to receive input which would shorten life expectancies and as a result is inherently biased.

8. SDG&E's depreciation methodology requires the independent application of judgment twice.

9. SDG&E's QAU model is based on speculative assumptions and not recorded data.

10. The depreciation analyst should consider all events which could affect plant lives at the same time and adjust average service lives accordingly.

11. A reasonable approach to determine average service plant lives should solicit information from experts, provide their identity, describe their input, and indicate how the information was applied.

12. A procedure similar to represcription is reasonable and should be adopted for SDG&E.

13. Depreciation workshops as previously described should be adopted for SDG&E's future general rate proceedings.

14. DRA's recommended depreciation expense and accruals, which exclude QAU, should be adopted.

15. SDG&E and DRA should address the issue of technical depreciation updates in SDG&E's next general rate proceeding.

16. SDG&E's life extending programs, pole butt treatment, underground switch maintenance, and padmount painting should be considered in determining the average remaining lives for the affected plant.

17. SDG&E should be provided an additional $200,000 in W/MBE funding for its participation in the clearinghouse for verifying W/MBEs.

18. SDG&E should encourage W/MBE joint ventures and provide technical assistance in meeting financing and insurance requirements at competitive rates.

19. SDG&E's attrition mechanism should use a four-year average excluding non-recurring and hazardous waste projects to estimate plant additions.

20. The integrated voice and data network project is expected to reoccur in attrition years 1990 and 1991 and should be included in the four-year average of plant additions.

21. SDG&E's estimated plant additions for attrition years should not be adjusted for changes in escalation rates.

22. Edison's budget for 1990 nuclear plant additions should be adopted for use in SDG&E's attrition year 1990 filing.

23. The nuclear O&M expenses and plant estimates adopted in Edison's 1991 test year general rate proceeding should be used for SDG&E's attrition year 1991 filing.

24. DRA's marginal energy costs revised to reflect the appropriate revenue-related tax factor, and marginal demand costs as shown in Appendix E should be adopted.

25. For directly assignable costs the following UCAN recommendations should be adopted: (1) no contingency factor for TSM costs, (2) 4% for purchasing and warehousing transformer costs, (3) a weighted average of single-family and multi-family units for customers on schedule DR, (4) an overhead rate of 111%, and (5) transformer costs based on SDG&E's incremental cost.

26. DRA's weighting of single-family and multi-family units and 10% real fixed rate for annualizing TSM costs should be adopted for determining directly assignable costs.

27. DRA's common distribution cost methodology should be adopted.

28. UCAN's recommendations that customer accounting costs reflect the differences in the cost of reading meters and exclude conservation expenses should be adopted.

29. DRA's market rental approach should be adopted for determining marginal customer costs.

30. DRA's revised marginal energy revenue determinants should be adopted.

31. Except for its reliability adjustment and diversity factor for residential class transmission and distribution demands, DRA's methodology, weighting factors, and demand determinants for calculating marginal cost revenues should be adopted.

32. A system peak of 2376 MW should be used for 1989 generation demand.

33. DRA's distribution and transmission demand adjusted for a 50% diversity factor for the residential class should be adopted.

34. The Full EPMC revenue allocation shown in Appendix D should be adopted.

35. The phased-in electric and gas baseline allowances shown in Appendices F and G are in conformance with PU § 739 and should be adopted.

36. A mobilehome park discount of of $9.50/unit/month for schedule DT and $6.00/unit/month, both to be prorated and billed on a daily basis, for schedule GT should be adopted.

37. A discount for apartment buildings of $4.04/unit/month for schedule DS and $1.90/unit/month, both to be prorated and billed on a daily basis, for schedule GS should be adopted.

38. Declining block energy rates encourage energy use and are not consistent with our conservation policies.

39. DRA's recommended $5.50/kw demand charge for schedule AD should be adopted.

40. Schedule A and AD customers should be allowed to move to a TOU schedule.

41. Maintaining the existing off-, mid-, and on-peak energy relationships should provide customers on schedules AL-TOU and A6-TOU with a better understanding of the adopted rates.

42. The off- and mid-peak energy rates for SDG&E's experimental schedules AE-1, R-TOU-1, and R-TOU-2 should be adjusted to reflect the adopted revenue requirement, but the schedules should be closed to new customers.

43. Three new real time pricing schedules which incorporate the rate structure changes to schedules AL-TOU and A6-TOU, should be adopted.

44. DRA's recommended interruptible service schedules should be adopted.

45. Customers with power factors below 90% should be assessed SDG&E's current charge of $0.21/kVAR month.

46. Customers should be provided six months to correct their power factors before being assessed a kVAR charge.

47. Revenues from power factor charges should be treated in the same manner as standby revenues.

48. The proposals to change SDG&E's current standby rate structure are not consistent with the standby policy adopted in D.86-12-091.

49. Schedule AD customers should be allowed to take standby service and receive credit for the non-coincident demand charges on their contracted standby load.

50. The energy netting provision of schedule PG should be closed to all customers and the schedule should be closed to new customers on June 30, 1989.

51. Consistent with D.87-12-069 schedule PG-QF should be closed to new cogeneration facilities above 20 kw by June 30, 1989.

52. SDG&E's agricultural rate design as shown in Appendix F should be adopted.

53. On or after March 1, 1989 SDG&E should be authorized to establish a late payment charge for non-residential customers. The charge should only apply to balances that have not been paid within 30 days from the billing date and be calculated by dividing SDG&E's authorized return on rate base by 12 and rounding the quotient to the nearest one tenth of one percent. Governmental facilities should not be charged a late payment fee that exceeds the amount authorized by the Government Code.

54. SDG&E should not enter special contracts which provide customers with reduced rates in a year when forecasts indicate the need for additional capacity. Such contracts should include considerable justification demonstrating the benefits for all SDG&E ratepayers.

55. DRA's EPMC revenue allocation for the street lighting class should be adopted.

56. CAL-SLA's EPMC unbundled street lighting rate design should be adopted because it focuses on the cost components that provide information on which service to purchase.

57. SDG&E should be authorized to revise non-core gas rates, effective January 1, 1989, to reflect the change in margin adopted in this decision. The current revenue allocation and rate design methodology should remain unchanged. The margin change allocable to the core gas customers of $10.335 million as shown in Appendix G, should be reflected in the core balancing account to be addressed in SDG&E's ACAP.

58. The non-core gas rates in Appendix G should be adopted.

59. SDG&E should be authorized to increase its electric, gas, and steam margins to reflect the revenue requirement shown in Appendix A.

60. DRA and SDG&E should conduct workshops with the signatories to the Stipulation and Agreement to identify the cost detail required for revenue allocation in SDG&E's ACAP. The results of these workshops should be served on all parties to this proceeding and SDG&E's last gas offset proceeding prior to SDG&E's ACAP filing.

61. SDG&E's proposed steam rate design as shown in Appendix E should be adopted.

62. Public Advocates, UCAN, CPIL, and Rate Watchers should be found eligible for compensation under Rule 76.54

63. CPIL should be awarded $3,582 in compensation for its contribution to D.88-07-023.

64. Rate Watchers should be awarded $2,038 in compensation for its contribution to D.88-07-023.

65. Interest should be paid on CPIL's and Rate Watchers' award from the 76th day after their request was filed until the payment of the award is made. The interest should be calculated in the same manner as the deferred account established in D.86-06-079.

66. UCAN should be awarded $44,907 for its contribution to D.88-09-063 and this decision.

67. Effective January 1, 1989 SDG&E should be directed to decrease its electric rates by $89.3 million or 7.0% and authorized to increase its gas rates for non-core customers by $1.6 million or 0.8% and steam rates by $0.5 million or 10.9%.

68. The electric, gas, and steam rates shown in Appendices E, F, and G are reasonable and should be adopted.

69. The decreases and increases in rates and charges authorized by this decision are justified, and are just and reasonable.

INTERIM ORDER

IT IS ORDERED that:

1. San Diego Gas & Electric Company (SDG&E) is authorized and directed to file with this Commission, on or after the effective date of this order, and not later than December 28, 1988, revised tariff schedules for electric, gas, and steam rates as set forth in Appendices F, G, and H.

2. The revised tariff schedules shall become effective on or after January 1, 1989 and shall comply with General Order 96-A. The revised tariffs shall apply to service rendered on or after their effective date.

3. SDG&E is authorized to increase its electric, gas, and steam margins to reflect the adopted revenue requirement shown in Appendix A, and to reflect the split of core and non-core gas margin shown in Apendix G, page 2.

4. SDG&E is authorized to file attrition adjustments for the years 1990 and 1991 based on the methodology and revenue requirement set forth in Appendix B.

5. In its 1990 attrition year filing SDG&E shall amortize any difference between the estimated and actual CLMAC balance over two years.

6. SDG&E and the Division of Ratepayer Advocates (DRA) shall conduct depreciation workshops as discussed in this decision for SDG&E's future general rate proceedings.

7. SDG&E and DRA shall address the issue of technical depreciation updates in SDG&E's next general rate proceeding.

8. SDG&E shall encourage joint ventures with women- and minority-owned business and shall provide technical assistance in meeting financing and insurance requirements at competitive rates.

methodology should remain unchanged. The margin change allocable to the core gas customers of $______ million as shown in Appendix G, should be reflected in the core balancing account to be addressed in SDG&E's ACAP.

60. The non-core gas rates in Appendix G should be adopted.

61. SDG&E should be authorized to increase its electric, gas, and steam margins to reflect the revenue requirement shown in Appendix A.

62. DRA and SDG&E should conduct workshops with the signatories to the Stipulation and Agreement to identify the cost detail required for revenue allocation in SDG&E's 1989 ACAP. The results of these workshops should be served on all parties to this proceeding and SDG&E's last gas offset proceeding prior to SDG&E's 1989 ACAP filing.

63. SDG&E's proposed steam rate design as shown in Appendix H should be adopted.

64. Public Advocates, UCAN, CPIL, and Rate Watchers should be found eligible for compensation under Rule 76.54

65. CPIL should be awarded $3,582 in compensation for its contribution to D.88-07-023.

66. Rate Watchers should be awarded $2,038 in compensation for its contribution to D.88-07-023.

67. Interest should be paid on CPIL's and Rate Watchers' award from the 76th day after their request was filed until the payment of the award is made. The interest should be calculated in the same manner as the deferred account established in D.86-06-079.

68. UCAN should be awarded $53,118 for its contribution to D.88-09-063 and this decision.

69. Effective January 1, 1989 SDG&E should be directed to decrease its electric rates by $94.9 million or 7.6% and authorized to increase its gas rates for non-core customers by $___ million or ___% and steam rates by $0.6 million or 51.3%.

9. For its attrition year 1991 filing SDG&E is authorized to use the nuclear O&M expenses and plant estimates adopted in Southern California Edison Company's 1991 test year general rate proceeding.

10. DRA and SDG&E shall conduct workshops with the signatories to the Stipulation and Agreement to identify the cost detail required for revenue allocation in SDG&E's ACAP. The results of these workshops shall be served on all parties to this proceeding and SDG&E's last gas offset proceeding prior to SDG&E's ACAP filing.

11. Experimental schedules AE-1, R-TOU-1, and R-TOU-2 shall be closed to new customers on the effective date of this decision.

12. On June 30, 1989 schedule PG shall be closed to new customers and the schedule's energy netting provision shall be closed to all customers.

13. On June 30, 1989 schedule PG-QF shall be closed to new cogeneration facilities above 20 kW.

14. On or after SDG&E is authorized to establish a late payment charge for non-residential customers. The charge shall only apply to balances that have not been paid within 30 days from the billing date and be calculated by dividing SDG&E's authorized return on rate base by 12 and rounding the quotient to the nearest one tenth of one percent. Governmental facilities shall not be charged a late payment fee that exceeds the amount authorized by the Government Code.

15. SDG&E shall pay Center for Public Interest Law (CPIL) $3,582 and Rate Watchers $2,038 within 15 days from today in compensation for their contribution to D.88-07-023.

16. Interest shall be paid on CPIL's and Rate Watchers' award from the 76th day after their request was filed until the payment of the award is made and shall be calculated in the same manner as the deferred account established in D.86-06-079.

17. SDG&E shall pay Utility Consumers Action Network (UCAN) $44,907 within 15 days from today in compensation for its contribution to D.88-09-063 and this decision.

18. Public Advocates is eligible to request intervenor compensation for its contribution to this decision.

19. CPIL, Rate Watchers, and UCAN are placed on notice that they may be subject to audit or review by the Commission Advisory and Compliance Division pursuant to Rule 76.57; therefore, they shall maintain and retain adequate accounting records and other necessary documentation supporting all claims for intervenor compensation. They shall maintain such records in a manner that identifies specific issues for which compensation will be requested, the actual time spent by each employee, fees paid to consultants, and any other compensable costs incurred.

This order is effective today.

Dated DEC 19 1988, at San Francisco, California.

STANLEY W. HULETT
President
DONALD VIAL
FREDERICK R. DUDA
G. MITCHELL WILK
JOHN B. OHANIAN
Commissioners

SAN DIEGO GAS & ELECTRIC COMPANY
Electric Department
SUMMARY OF EARNINGS AT ADOPTED PRESENT RATE
REVENUES AND EXPENSES
(Thousands Of 1989 Dollars Unless Otherwise Indicated)
Test Year 1989

Description	Adopted
Operating Revenues	
Sales to customers	$784,259
Non-Jurisdictional	1,445
Miscellaneous	17,005
Total Operating Revenues	$802,709
Operating Expenses	
Operation & Maintenance	217,499
Nuclear refueling	4,319
Uncollectibles	15,348
Franchise Requirements	1,655
Subtotal (1986 Dollars)	$238,821
Labor Escalation Amount	12,903
Non-Labor Escalation Amount	10,719
Subtotal (1989 Dollars)	$262,442
Depreciation & Amortization	128,580
Nuclear Decommissioning	22,038
Taxes Other Than On Income	37,666
CA Corporation Franchise Tax	24,993
Federal Income Tax	90,409
Total Operating Expenses	$566,129
Net Operating Income	$236,580
Weighted Average Rate Base	$2,178,451
AUTHORIZED RATE OF RETURN	10.86%

Adopted Revenues at Adopted Rates	$802,709
Less: Stipulated Rev. at Present Rates	$888,468
Less: Amort. of Conservation/Load Mgmt. balancing account overcollection	$3,577
AUTHORIZED INCR. IN REVENUE REQUIREMENT	($89,336)

SAN DIEGO GAS & ELECTRIC COMPANY
Gas Department
SUMMARY OF EARNINGS AT ADOPTED PRESENT RATE
REVENUES AND EXPENSES
(Thousands Of 1989 Dollars Unless Otherwise Indicated)
Test Year 1989

Description	Adopted
Operating Revenues	
Sales to customers	$114,971
Interdepartmental	14,051
Miscellaneous	3,152
Total Operating Revenues	$132,174
Operating Expenses	
Operation & Maintenance	48,577
Uncollectibles	2,551
Franchise Requirements	243
Subtotal (1986 Dollars)	$51,371
Labor Escalation Amount	3,301
Non-Labor Escalation Amount	1,995
Subtotal (1989 Dollars)	$56,667
Depreciation & Amortization	23,056
Taxes Other Than On Income	5,516
CA Corporation Franchise Tax	4,015
Federal Income Tax	13,137
Total Operating Expenses	$102,391
Net Operating Income	$29,783
Weighted Average Rate Base	$274,248
AUTHORIZED RATE OF RETURN	10.86%

Adopted Revenues at Adopted Rates	$132,174
Less: Stipulated Rev. at Present Rates	$121,823
Less: Amort. of Conservation/Load Mgmt. balancing account overcollection	$1,198
AUTHORIZED INCR. IN REVENUE REQUIREMENT	$9,153

SAN DIEGO GAS & ELECTRIC COMPANY
Steam Department
SUMMARY OF EARNINGS AT ADOPTED PRESENT RATE
REVENUES AND EXPENSES
(Thousands Of 1989 Dollars Unless Otherwise Indicated)
Test Year 1989

Description	Adopted
Operating Revenues	
Sales to customers	$1,455
Miscellaneous	0
Total Operating Revenues	$1,455
Operating Expenses	
Operation & Maintenance	1,182
Uncollectibles	28
Franchise Requirements	0
Subtotal (1986 Dollars)	$1,210
Labor Escalation Amount	80
Non-Labor Escalation Amount	62
Subtotal (1989 Dollars)	$1,352
Depreciation & Amortization	39
Taxes Other Than On Income	46
CA Corporation Franchise Tax	(3)
Federal Income Tax	(5)
Total Operating Expenses	$1,430
Net Operating Income	$25
Weighted Average Rate Base	$233
AUTHORIZED RATE OF RETURN	10.86%

Adopted Revenues at Adopted Rates	$1,455
Less: Stipulated Rev. at Present Rates	$954
AUTHORIZED INCR. IN REVENUE REQUIREMENT	$501

SAN DIEGO GAS & ELECTRIC COMPANY
Electric Department - BASE RATE REVENUES
Gas Department - BASE COST AMOUNT
Steam Department - BASE RATE REVENUES
(Thousands Of 1989 Dollars Unless Otherwise Indicated)
Test Year 1989

Electric Department

Adopted Revenues at Adopted Rates	$802,709
Less: Non-Jurisdictional Revenues	1,445
Less: Miscellaneous Revenues	17,005
Less: Amort. of Conservation/Load Mgmt. balancing account overcollection	3,577
AUTHORIZED BASE RATE REVENUES	$780,682
Less: Auth. Base Rate Rev. eff. 4/1/88	764,701
ADOPTED INCREASE IN BASE RATE REVENUES	$15,980
% INCREASE IN BASE RATE REVENUES	2.09%

Gas Department

Adopted Revenues at Adopted Rates	$132,174
Less: Amort. of Conservation/Load Mgmt. balancing account overcollection	1,198
AUTHORIZED BASE COST AMOUNT	$130,976
Less: Base Cost Amount eff. 1/1/88	118,448
ADOPTED INCREASE IN BASE COST AMOUNT	$12,528
% INCREASE IN BASE COST AMOUNT	10.58%

Steam Department

AUTHORIZED BASE RATE REVENUES	$1,455
Less: Auth. Base Rate Rev. eff. 1/1/88	1,831
ADOPTED INCREASE IN BASE RATE REVENUES	($376)
% INCREASE IN BASE RATE REVENUES	-20.54%

SAN DIEGO GAS & ELECTRIC COMPANY
ESCALATION FACTORS - Total Company
COST OF CAPITAL - CPUC Jurisdiction
NET-TO-GROSS MULTIPLIERS
Test Year 1989

Description		Adopted
LABOR ------------>	1987	3.970%
ESCALATION FACTORS	1988	3.805%
	1989	4.201%
	1990	4.816%
	1991	4.932%
NON-LABOR --------->	1987	2.625%
ESCALATION FACTORS	1988	4.986%
	1989	4.719%
	1990	5.086%
	1991	5.334%
OTHER ------------>	ALL YEARS	0.000%

COMPOSITE ESCALATION FACTORS		
LABOR	1986 TO 1989	12.460%
NON-LABOR	1986 TO 1989	12.826%
OTHER	1986 TO 1989	0.000%

	Electric Dept.	Gas Dept.	Steam Dept.
Uncollectibles	0.019570	0.022190	0.019570
Franchise Fee	0.002110	0.002110	0.000000
State Inc. Tax	0.093000	0.093000	0.093000
Fed. Inc. Tax	0.340000	0.340000	0.340000
FF&U Factor	1.022117	1.024856	1.019961
Inc.Tax Factor	1.670509	1.670509	1.670509
N-T-G Multipli	1.707456	1.712031	1.703853

	COST	CAPITALIZATION	WTD. COST
Debt	9.24%	40.50%	3.74%
Pref. Stock	7.28%	8.50%	0.62%
Common equity	12.75%	51.00%	6.50%
Auth. Return on Rate Base (CPUC Jurisdiction) :			10.86%

(END OF APPENDIX A)

SAN DIEGO GAS & ELECTRIC COMPANY
Electric Department
ATTRITION YEAR 1990

	Expenses for AY1990 in 000's of 1989$	Expenses for AY1990 in 000's of 1989$ (Calif.)	Transfer of Other Expenses to Labor/ Non-Labor	Expenses for AY1990 in 000's of 1989$ for Attrition purposes
	A D O P T E D I N G R C			
Oper. & Maint. Expenses (Juris. Alloc. Factor = 1.0000)				
Labor	116,113	116,113	0	116,113
Non Labor	89,761	89,761	21,190	110,951
Other	34,694	34,694	(21,190)	13,504
	240,568	240,568	0	240,568
Uncollectibles (Juris. Alloc. Factor = 1.0000)				
Labor	0	0	0	0
Non Labor	0	0	0	0
Other	15,348	15,348	0	15,348
	15,348	15,348	0	15,348
Franchise Fees (Juris. Alloc. Factor = 1.0000)				
Labor	0	0	0	0
Non Labor	0	0	0	0
Other	1,655	1,655	0	1,655
	1,655	1,655	0	1,655
TOTAL O&M EXPENSES				
Labor	116,113	116,113	0	116,113
Non Labor	89,761	89,761	21,190	110,951
Other	51,697	51,697	(21,190)	30,507
	257,571	257,571	0	257,571

Federal Tax Depr. (Juris. Alloc. Factor =		1.0000)	
Federal Tax Depr. Rate (Adopted in GRC)		2.7280%	
Increase in AY1990 EOY Plant in Service from TY1989 EOY Plant in Service at a wtd-to-net ratio of 0.4495 (Adopted in GRC)		165,775	
Increase in Federal Tax Depreciation		4,522	
Increase in Federal Tax Depreciation (Calif.)		4,522	
Increase in Federal Taxes (Tax Rate	34.0000%	(1,538)	
Net-to-Gross Multiplier (Adopted in GRC)		1.707456	
Increase in Revenue Requirement		(2,625)	(11)
ITC Normalized (Juris. Alloc. Factor = (Applicable to IRC Sec. 46(f)(2) utilities only.)		1.0000)	
Attrition Year 1990 (Adopted in GRC)		(4,681)	
Test Year 1989 (Adopted in GRC)		(4,681)	
Increase in ITC normalized		0	
Increase in ITC normalized (Calif.)		0	
Net-to-Gross Multiplier (Adopted in GRC)		1.707456	
Increase in Revenue Requirement		0	(12)
Interest Synchro. (Juris. Alloc. Factor = (Applicable to IRC Sec. 46(f)(2) utilities only.)		1.0000)	
ITC Normalized in TY1989 (from above)		4,681	
Wtd. cost of Long Term Debt (Adopted in AY1990)		3.74%	
Increase in CCFT interest		175	
Increase in CCFT (Tax Rate =	9.3000%	(16)	
Increase in FIT (Tax Rate =	34.0000%	6	
Increase in State & Federal Taxes		(11)	
Increase in State & Federal Taxes (Calif.)		(11)	
Net-to-Gross Multiplier (Adopted in GRC)		1.707456	
Increase in Revenue Requirement		(18)	(13)

Rate Base (Juris. Alloc. Factor =	1.0000)
Wtd. avg. Depr Rate Base for TY1989 (Adopted in GRC	2,178,451
Plant in Service (Adopted in GRC)	
Wtd. avg. Additions for TY1989	(84,576)
Net Additions for TY1989	189,984
Wtd. avg. Additions for AY1990	74,516
PHFU (Adopted in GRC)	
Wtd. avg. Additions for TY1989	0
Net Additions for TY1989	0
Wtd. avg. Additions for AY1990	0
Depreciation Reserve (Adopted in GRC)	
Wtd. avg. Depreciation Reserve for TY1989	990,633
Wtd. avg. Depreciation Reserve for AY1990	(1,114,496)
Taxes Deferred - ACRS (Adopted in GRC)	
Wtd. avg. Deferred Taxes - MACRS for TY1989	207,459
Wtd. avg. Deferred Taxes - MACRS for AY1990	(229,244)
Taxes Deferred - Amort & Other (Adopted in GRC)	
Wtd. avg. Deferred Taxes - Amort & Other for TY1989	9,593
Wtd. avg. Deferred Taxes - Amort & Other for AY1989	(11,950)
Wtd. avg. Depr Rate Base for AY1990	2,210,370
Wtd. avg. Depr. Rate Base in TY1989 (Adopted in GRC	2,178,451
Wtd. avg. Depr. Rate Base in AY1990 (Adopted in GRC	2,210,370
Wtd. avg. Depr. Rate Base in TY 1989 (Calif.)	2,178,451
Wtd. avg. Depr. Rate Base in AY 1990 (Calif.)	2,210,370
Long-term Debt	
Return on Debt in TY 1989 (Adopted in GRC)	9.24%
Debt capitalization in TY 1989 (Adopted in GRC)	40.50%
Wtd. cost of Debt for Test Year 1989	3.74%
Return on Debt in AY 1990 (Adopted in AY1989)	9.24%
Debt capitalization in AY 1990 (Adopted in AY1989)	40.50%
Wtd. cost of Debt for Attrition Year 1990	3.74%
Increase in Debt cost in Attrition Year 1990	1,194
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.022117
Increase in Revenue Requirement	1,220 (14)

Preferred Stock

Return on Pref. Stock in TY 1989 (Adopted in GRC)	7.28%	
Pref.Stk. capitalization in TY1989 (Adopted in GRC)	8.50%	
Wtd. cost of Preferred Stock for Test Year 1989	0.62%	
Return on Pref. Stock in AY1990 (Adopted in AY1990)	7.28%	
Pref.Stk. capitalization AY1990 (Adopted in AY1990)	8.50%	
Wtd. cost of Preferred Stock for Att. Year 1990	0.62%	
Increase in Pref. Stock cost in Att. Year 1990	198	
Net-to-Gross Multiplier (Adopted in GRC)	1.707456	
Increase in Revenue Requirement	338	(15)

Common Equity

Return on Common Equity in TY 1989 (Adopted in GRC)	12.75%	
Com. Equity capitalization TY 1989 (Adopted in GRC)	51.00%	
Wtd. cost of Common Equity for Test Year 1989	6.50%	
Return on Common Equity AY 1990 (Adopted in AY1990)	12.75%	
Com. Eq. capitalization AY 1990 (Adopted in AY1990)	51.00%	
Wtd. cost of Common Equity for Att. Year 1990	6.50%	
Increase in Common Equity cost in Att. Year 1990	2,075	
Net-to-Gross Multiplier (Adopted in GRC)	1.707456	
Increase in Revenue Requirement	3,543	(16)

RD&D expense (CIEE funding)

Attrition Year 1990 (Adopted in GRC)	225	
Test Year 1989 (Adopted in GRC)	100	
Increase in RD&D expense	125	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.022117	
Increase in Revenue Requirement	128	(17)

RATEBASE MONITORING

Wtd. avg. Depr.RateBase in TY1989 (Adopted in GRC)	2,178,451
Wtd. avg. Depr.RateBase in TY1989 (use updated est.	2,178,451
Wtd. avg. Depr.RateBase in AY1990 (Adopted in GRC)	2,210,370
Wtd. avg. Depr.RateBase in AY1990 (use updated est.	2,210,370

SAN DIEGO GAS & ELECTRIC COMPANY
Electric Department
REVENUE REQUIREMENTS FOR ATTRITION YEAR 1990
Thousands Of 1990$

ITEM	ATTRITION YEAR 1990	
O & M EXPENSES :		
Labor Escalation	$5,716	(1)
Non-Labor Escalation	5,768	(2)
Total O&M Expenses	11,483	
NUCLEAR REFUELING EXPENSES :		
Labor Escalation	17	(3)
Additional Labor Base	(12)	(4)
Non-Labor Escalation	236	(5)
Additional Non-Labor Base	2,294	(6)
Total Nuclear Refueling Expenses	2,534	
CAPITAL RELATED ITEMS :		
Book Depreciation Expenses	11,447	(7)
Ad Valorem Taxes	1,584	(8)
Accelerated Amortization	0	(9)
State Tax Depreciation	(660)	(10)
Federal Tax Depreciation	(2,625)	(11)
ITC normalized	0	(12)
Interest Synchronization	(18)	(13)
Debt cost	1,220	(14)
Preferred Stock cost	338	(15)
Common Equity cost	3,543	(16)
Total Capital Related Items	14,829	
OTHER AUTHORIZED ITEMS :		
RD&D expense (CIEE funding)	128	(17)
Retirement of debt (Adopted in AY 1990)	(0)	
Book Depreciation exp. adj. (Adopted in AY1990)	0	
Incr. in Non-Jurisdictional Rev. (Adopted in GRC	0	
Amort. of CLMAC bal. account (Adopted in AY1990)	(0)	
Total Other Authorized Items	128	
ADD'L REVENUE REQUIREMENTS ---->	$28,974	
Exclude % attributable to Large Light & Power (To be adopted in OIR 86-10-001)	0.00%	
TOTAL ADD'L REVENUE REQUIREMENTS ---->	28,974	

Federal Tax Depr. (Juris. Alloc. Factor =		1.0000)	
Federal Tax Depr. Rate (Adopted in GRC)		2.7280%	
Increase in AY1991 EOY Plant in Service from AY1990 EOY Plant in Service at a wtd-to-net ratio of 0.45798 (Updated in AY1991)		196,491	
Increase in Federal Tax Depreciation		5,360	
Increase in Federal Tax Depreciation (Calif.)		5,360	
Increase in Federal Taxes (Tax Rate	34.0000%	(1,822)	
Net-to-Gross Multiplier (Adopted in GRC)		1.707456	
Increase in Revenue Requirement		(3,112)	(28)

ITC Normalized (Juris. Alloc. Factor = (Applicable to IRC Sec. 46(f)(2) utilities only.)		1.0000)	
Attrition Year 1991 (Adopted in GRC)		(4,681)	
Attrition Year 1990 (adopted in GRC)		(4,681)	
Increase in ITC normalized		0	
Increase in ITC normalized (Calif.)		0	
Net-to-Gross Multiplier (Adopted in GRC)		1.707456	
Increase in Revenue Requirement		0	(29)

INTEREST SYNCHRO. (Juris. Alloc. Factor = (Applicable to IRC Sec. 46(f)(2) utilities only.))		1.0000)	
ITC Normalized in AY1991 (from above)		4,681	
Wtd. cost of Long Term Debt (Adopted in AY1991)		3.74%	
Increase in CCFT interest		175	
Increase in CCFT (Tax Rate =	9.3000%	(16)	
Increase in FIT (Tax Rate =	34.0000%	6	
Increase in State & Federal Taxes		(11)	
Increase in State & Federal Taxes (Calif.)		(11)	
Net-to-Gross Multiplier (Adopted in GRC)		1.707456	
Increase in Revenue Requirement		(18)	(30)

Rate Base (Juris. Alloc. Factor =	1.0000)
Wtd. avg. Depr Rate Base for AY1990 (Adopted in GRC	2,210,370
Plant in Service (Adopted in GRC)	
Wtd. avg. Additions for AY1990 (Adopted in GRC)	(74,516)
Net Additions for AY1990 (Adopted in GRC)	165,775
Wtd. avg. Additions for AY1991 (Adopted in AY1991)	89,989
PHFU (Adopted in GRC)	
Wtd. avg. Additions for AY1990 (Adopted in GRC)	0
Net Additions for AY1990 (Adopted in GRC)	0
Wtd. avg. Additions for AY1991 (Adopted in AY1991)	0
Depreciation Reserve	
Wtd. avg. Depr. Reserve for AY1990 (Adopted in GRC)	1,114,496
Wtd. avg. Depr. Rsrv. for AY1991 (Updated in AY1991	(1,244,786)
Taxes Deferred - ACRS	
Wtd. avg. Def. Taxes - MACRS for AY1990 (Adopted in	229,244
Wtd. avg. Def. Taxes - MACRS for AY1991 (Updated in	(250,287)
Taxes Deferred - Amort & Other (Adopted in GRC)	
Wtd. avg. Deferred Taxes - Amort & Other for TY1989	11,950
Wtd. avg. Deferred Taxes - Amort & Other for AY1989	(14,204)
Wtd. avg. Depr Rate Base for AY1991	2,238,031
Wtd. avg. Depr. Rate Base in Attrition Year 1990	2,210,370
Wtd. avg. Depr. Rate Base in Attrition Year 1991	2,238,031
Wtd. avg. Depr. Rate Base in AY 1990 (Calif.)	2,210,370
Wtd. avg. Depr. Rate Base in AY 1991 (Calif.)	2,238,031
Long-term Debt	
Return on Debt in AY 1990 (Adopted in AY1990)	9.24%
Debt capitalization in AY 1990 (Adopted in AY1990)	40.50%
Wtd. cost of Debt for Attrition Year 1990	3.74%
Return on Debt in AY 1991 (Adopted in AY1991)	9.24%
Debt capitalization in AY 1991 (Adopted in AY1991)	40.50%
Wtd. cost of Debt for Attrition Year 1991	3.74%
Increase in Debt cost in Attrition Year 1991	1,035
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.022117
Increase in Revenue Requirement	1,057

Preferred Stock

Return on Pref. Stock in AY 1990 (Adopted in AY1990	7.28%	
Pref.Stk. capitalization AY 1990 (Adopted in AY1990	8.50%	
Wtd. cost of Preferred Stock for Test Year 1990	0.62%	
Return on Pref. Stock in AY 1991 (Adopted in AY1991	7.28%	
Pref.Stk. capitalization AY 1991 (Adopted in AY1991	8.50%	
Wtd. cost of Preferred Stock for Att. Year 1991	0.62%	
Increase in Pref. Stock cost in Att. Year 1991	171	
Net-to-Gross Multiplier (Adopted in GRC)	1.707456	
Increase in Revenue Requirement	293	(32)

Common Equity

Return on Com. Eq. in AY 1990 (Adopted in AY1990)	12.75%	
Com. Eq. capitalization AY 1990 (Adopted in AY1990)	51.00%	
Wtd. cost of Common Equity for Test Year 1990	6.50%	
Return on Com. Eq. in AY 1991 (Adopted in AY1991)	12.75%	
Com. Eq. capitalization AY 1991 (Adopted in AY1991)	51.00%	
Wtd. cost of Common Equity for Att. Year 1991	6.50%	
Increase in Common Equity cost in Att. Year 1991	1,798	
Net-to-Gross Multiplier (Adopted in GRC)	1.707456	
Increase in Revenue Requirement	3,070	(33)

RD&D expense (CIEE funding)

Attrition Year 1991 (Adopted in GRC)	350	
Attrition Year 1990 (Adopted in GRC)	225	
Increase in RD&D expense	125	
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.022117	
Increase in Revenue Requirement	128	(34)

Retirement of debt

Increase in Revenue Requirement (Adopted in AY1991)	(0)	

SAN DIEGO GAS & ELECTRIC COMPANY
Electric Department
REVENUE REQUIREMENTS FOR ATTRITION YEAR 1991
Thousands Of 1991$

ITEM	ATTRITION YEAR 1991	
O & M EXPENSES :		
Labor Escalation	$6,135	(18)
Non-Labor Escalation	6,357	(19)
Total O&M Expenses	12,492	
NUCLEAR REFUELING EXPENSES :		
Labor Escalation	17	(20)
Additional Labor Base	9	(21)
Non-Labor Escalation	382	(22)
Additional Non-Labor Base	(2,842)	(23)
Total Nuclear Refueling Expenses	(2,433)	
CAPITAL RELATED ITEMS :		
Book Depreciation Expenses	11,531	(24)
Ad Valorem Taxes	1,878	(25)
Accelerated Amortization	0	(26)
State Tax Depreciation	(782)	(27)
Federal Tax Depreciation	(3,112)	(28)
ITC normalized	0	(29)
Interest Synchronization	(18)	(30)
Debt cost	1,057	(31)
Preferred Stock cost	293	(32)
Common Equity cost	3,070	(33)
Total Capital Related Items	13,917	
OTHER AUTHORIZED ITEMS :		
RD&D expense (CIEE funding)	128	(34)
Retirement of debt (Adopted in AY 1991)	(0)	
Book Depreciation exp. adj. (Adopted in AY1991)	0	
Incr. in Non-Jurisdictional Rev. (Adopted in GRC	0	
Amort. of CLMAC bal. account (Adopted in AY1990)	(0)	
Total Other Authorized Items	128	
ADD'L REVENUE REQUIREMENTS ---->	$24,104	
Exclude % attributable to Large Light & Power (To be adopted in OIR 86-10-001)	0.00%	
TOTAL ADD'L REVENUE REQUIREMENTS ---->	24,104	

SAN DIEGO GAS & ELECTRIC COMPANY
Gas Department
ATTRITION YEAR 1990

	Expenses for AY1990 in 000's of 1989$	Expenses for AY1990 in 000's of 1989$ (Calif.)	Transfer of Other Expenses to Labor/ Non-Labor	for Expenses for AY1990 in 000's of 1989$ for Attrition purposes
	A D O P T E D I N G R C			
Oper. & Maint. Expenses (Juris. Alloc. Factor =				**1.0000)**
Labor	29,790	29,790	0	29,790
Non Labor	17,552	17,552	5,034	22,586
Other	6,531	6,531	(5,034)	1,497
	53,873	53,873	0	53,873
Uncollectibles (Juris. Alloc. Factor =				**1.0000)**
Labor	0	0	0	0
Non Labor	0	0	0	0
Other	2,551	2,551	0	2,551
	2,551	2,551	0	2,551
Franchise Fees (Juris. Alloc. Factor =				**1.0000)**
Labor	0	0	0	0
Non Labor	0	0	0	0
Other	243	243	0	243
	243	243	0	243
TOTAL O&M EXPENSES				
Labor	29,790	29,790	0	29,790
Non Labor	17,552	17,552	5,034	22,586
Other	9,325	9,325	(5,034)	4,291
	56,667	56,667	0	56,667

Federal Tax Depr. (Juris. Alloc. Factor =		1.0000)	
Federal Tax Depr. Rate (Adopted in GRC)		2.8582%	
Increase in AY1990 EOY Plant in Service from TY1989 EOY Plant in Service at wtd-to-net ratio of 0.44303 (Adopted in GRC)		41,882	
Increase in Federal Tax Depreciation		1,197	
Increase in Federal Tax Depreciation (Calif.)		1,197	
Increase in Federal Taxes (Tax Rate	34.0000%	(407)	
Net-to-Gross Multiplier (Adopted in GRC)		1.712031	
Increase in Revenue Requirement		(697)	(41)

ITC Normalized (Juris. Alloc. Factor =		1.0000)	
(Applicable to IRC Sec. 46(f)(2) utilities only.)			
Attrition Year 1990 (Adopted in GRC)		(345)	
Test Year 1989 (Adopted in GRC)		(345)	
Increase in ITC normalized		0	
Increase in ITC normalized (Calif.)		0	
Net-to-Gross Multiplier (Adopted in GRC)		1.712031	
Increase in Revenue Requirement		0	(42)

Interest Synchronization (Juris. Alloc. Factor =		1.0000)	
(Applicable to IRC Sec. 46(f)(2) utilities only.)			
ITC Normalized in TY1989 (from above)		345	
Wtd. cost of Long Term Debt (Adopted in AY1990)		3.74%	
Increase in CCFT interest		13	
Increase in CCFT (Tax Rate =	9.3000%	(1)	
Increase in FIT (Tax Rate =	34.0000%	0	
Increase in State & Federal Taxes		(1)	
Increase in State & Federal Taxes (Calif.)		(1)	
Net-to-Gross Multiplier (Adopted in GRC)		1.712031	
Increase in Revenue Requirement		(1)	(43)

Rate Base (Juris. Alloc. Factor =	1.0000
Wtd. avg. Depr Rate Base for TY1989 (Adopted in GRC	274,248
Plant in Service (Adopted in GRC)	
Wtd. avg. Additions for TY1989	(16,767)
Net Additions for TY1989	37,007
Wtd. avg. Additions for AY1990	18,555
PHFU (Adopted in GRC)	
Wtd. avg. Additions for TY1989	0
Net Additions for TY1989	0)
Wtd. avg. Additions for AY1990	0
Depreciation Reserve (Adopted in GRC)	
Wtd. avg. Depreciation Reserve for TY1989	197,332
Wtd. avg. Depreciation Reserve for AY1990	(218,626)
Taxes Deferred - ACRS (Adopted in GRC)	
Wtd. avg. Deferred Taxes - MACRS for TY1989	9,503
Wtd. avg. Deferred Taxes - MACRS for AY1990	(11,142)
Taxes Deferred - Amort & Other (Adopted in GRC)	
Wtd. avg. Deferred Taxes - Amort & Other for TY1989	1,225
Wtd. avg. Deferred Taxes - Amort & Other for AY1990	(1,444)
Wtd. avg. Depr Rate Base for AY1990	289,891
Wtd. avg. Depr. Rate Base in TY1989 (Adopted in GRC	274,248
Wtd. avg. Depr. Rate Base in AY1990 (Adopted in GRC	289,891
Wtd. avg. Depr. Rate Base in TY 1989 (Calif.)	274,248
Wtd. avg. Depr. Rate Base in AY 1990 (Calif.)	289,891
Long-term Debt	
Return on Debt in TY 1989 (Adopted in GRC)	9.24%
Debt capitalization in TY 1989 (Adopted in GRC)	40.50%
Wtd. cost of Debt for Test Year 1989	3.74%
Return on Debt in AY 1990 (Adopted in AY1989)	9.24%
Debt capitalization in AY 1990 (Adopted in AY1989)	40.50%
Wtd. cost of Debt for Attrition Year 1990	3.74%
Increase in Debt cost in Attrition Year 1990	585
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.024856
Increase in Revenue Requirement	600 (44)

Preferred Stock

Return on Pref. Stock in TY 1989 (Adopted in GRC)	7.28%	
Pref.Stk. capitalization in TY1989 (Adopted in GRC)	8.50%	
Wtd. cost of Preferred Stock for Test Year 1989	0.62%	
Return on Pref. Stock in AY1990 (Adopted in AY1990)	7.28%	
Pref.Stk. capitalization AY1990 (Adopted in AY1990)	8.50%	
Wtd. cost of Preferred Stock for Att. Year 1990	0.62%	
Increase in Pref. Stock cost in Att. Year 1990	97	
Net-to-Gross Multiplier (Adopted in GRC)	1.712031	
Increase in Revenue Requirement	166	(45)

Common Equity

Return on Common Equity in TY 1989 (Adopted in GRC)	12.75%	
Com. Equity capitalization TY 1989 (Adopted in GRC)	51.00%	
Wtd. cost of Common Equity for Test Year 1989	6.50%	
Return on Common Equity AY 1990 (Adopted in AY1990)	12.75%	
Com. Eq. capitalization AY 1990 (Adopted in AY1990)	51.00%	
Wtd. cost of Common Equity for Att. Year 1990	6.50%	
Increase in Common Equity cost in Att. Year 1990	1,017	
Net-to-Gross Multiplier (Adopted in GRC)	1.712031	
Increase in Revenue Requirement	1,741	(46)

Retirement of debt

Increase in Revenue Requirement (Adopted in AY1990)	(0)

RATEBASE MONITORING

Wtd. avg. Depr.RateBase in TY1989 (Adopted in GRC)	274,248
Wtd. avg. Depr.RateBase in TY1989 (use updated est.	274,248
Wtd. avg. Depr.RateBase in AY1990 (Adopted in GRC)	289,891
Wtd. avg. Depr.RateBase in AY1990 (use updated est.	289,891

SAN DIEGO GAS & ELECTRIC COMPANY
Gas Department
REVENUE REQUIREMENTS FOR ATTRITION YEAR 1990
Thousands Of 1990$

ITEM	ATTRITION YEAR 1990	
O & M EXPENSES :		
Labor Escalation	$1,478	(35)
Non-Labor Escalation	1,126	(36)
Total O&M Expenses	2,605	
CAPITAL RELATED ITEMS :		
Book Depreciation Expenses	2,822	(37)
Ad Valorem Taxes	324	(38)
Accelerated Amortization	0	(39)
State Tax Depreciation	(130)	(40)
Federal Tax Depreciation	(697)	(41)
ITC normalized	0	(42)
Interest Synchronization	(1)	(43)
Debt cost	600	(44)
Preferred Stock cost	166	(45)
Common Equity cost	1,741	(46)
Total Capital Related Items	4,824	
OTHER AUTHORIZED ITEMS :		
Retirement of debt (Adopted in AY 1990)	(0)	
Book Depreciation exp. adj. (Adopted in AY1990)	0	
Amort. of CLMAC bal. account (Adopted in AY1990)	(0)	
Total Other Authorized Items	(0)	
TOTAL ADD'L REVENUE REQUIREMENTS ---->	$7,428	

Federal Tax Depr. (Juris. Alloc. Factor =		1.0000)	
Federal Tax Depr. Rate (Adopted in GRC)		2.8582%	
Increase in AY1991 EOY Plant in Service from TY1990 EOY Plant in Service at wtd-to-net ratio of 0.43688 (Adopted in GRC)		45,495	
Increase in Federal Tax Depreciation		1,300	
Increase in Federal Tax Depreciation (Calif.)		1,300	
Increase in Federal Taxes (Tax Rate	34.0000%	(442)	
Net-to-Gross Multiplier (Adopted in GRC)		1.712031	
Increase in Revenue Requirement		(757)	(53)
ITC Normalized (Juris. Alloc. Factor = (Applicable to IRC Sec. 46(f)(2) utilities only.)		1.0000)	
Attrition Year 1991 (Adopted in GRC)		(345)	
Attrition Year 1990 (adopted in GRC)		(345)	
Increase in ITC normalized		0	
Increase in ITC normalized (Calif.)		0	
Net-to-Gross Multiplier (Adopted in GRC)		1.712031	
Increase in Revenue Requirement		0	(54)
INTEREST SYNCHRO. (Juris. Alloc. Factor = (Applicable to IRC Sec. 46(f)(2) utilities only.))		1.0000)	
ITC Normalized in AY1991 (from above)		345	
Wtd. cost of Long Term Debt (Adopted in AY1991)		3.74%	
Increase in CCFT interest		13	
Increase in CCFT (Tax Rate =	9.3000%	(1)	
Increase in FIT (Tax Rate =	34.0000%	0	
Increase in State & Federal Taxes		(1)	
Increase in State & Federal Taxes (Calif.)		(1)	
Net-to-Gross Multiplier (Adopted in GRC)		1.712031	
Increase in Revenue Requirement		(1)	(55)

Rate Base (Juris. Alloc. Factor =	1.0000)
Wtd. avg. Depr Rate Base for AY1990 (Adopted in GRC	289,891
Plant in Service (Adopted in GRC)	
Wtd. avg. Additions for AY1990	(18,555)
Net Additions for AY1990	41,882
Wtd. avg. Additions for AY1991	19,876
PHFU (Adopted in GRC)	
Wtd. avg. Additions for AY1990	0
Net Additions for AY1990	0
Wtd. avg. Additions for AY1991	0
Depreciation Reserve (Adopted in GRC)	
Wtd. avg. Depreciation Reserve for AY1990	218,626
Wtd. avg. Depreciation Reserve for AY1991	(241,615)
Taxes Deferred - ACRS (Adopted in GRC)	
Wtd. avg. Deferred Taxes - MACRS for AY1990	11,142
Wtd. avg. Deferred Taxes - MACRS for AY1991	(12,760)
Taxes Deferred - Amort & Other (Adopted in GRC)	
Wtd. avg. Deferred Taxes - Amort & Other for AY1990	1,444
Wtd. avg. Deferred Taxes - Amort & Other for AY1991	(1,663)
Wtd. avg. Depr Rate Base for AY1991	308,268
Wtd. avg. Depr. Rate Base in Attrition Year 1990	289,891
Wtd. avg. Depr. Rate Base in Attrition Year 1991	308,268
Wtd. avg. Depr. Rate Base in AY 1990 (Calif.)	289,891
Wtd. avg. Depr. Rate Base in AY 1991 (Calif.)	308,268
Long-term Debt	
Return on Debt in AY 1990 (Adopted in AY1990)	9.24%
Debt capitalization in AY 1990 (Adopted in AY1990)	40.50%
Wtd. cost of Debt for Attrition Year 1990	3.74%
Return on Debt in AY 1991 (Adopted in AY1991)	9.24%
Debt capitalization in AY 1991 (Adopted in AY1991)	40.50%
Wtd. cost of Debt for Attrition Year 1991	3.74%
Increase in Debt cost in Attrition Year 1991	687
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.024856
Increase in Revenue Requirement	704

(56)

Preferred Stock

Return on Pref. Stock in AY 1990 (Adopted in AY1990	7.28%	
Pref.Stk. capitalization AY 1990 (Adopted in AY1990	8.50%	
Wtd. cost of Preferred Stock for Test Year 1990	0.62%	
Return on Pref. Stock in AY 1991 (Adopted in AY1991	7.28%	
Pref.Stk. capitalization AY 1991 (Adopted in AY1991	8.50%	
Wtd. cost of Preferred Stock for Att. Year 1991	0.62%	
Increase in Pref. Stock cost in Att. Year 1991	114	
Net-to-Gross Multiplier (Adopted in GRC)	1.712031	
Increase in Revenue Requirement	195	(57)

Common Equity

Return on Com. Eq. in AY 1990 (Adopted in AY1990)	12.75%	
Com. Eq. capitalization AY 1990 (Adopted in AY1990)	51.00%	
Wtd. cost of Common Equity for Test Year 1990	6.50%	
Return on Com. Eq. in AY 1991 (Adopted in AY1991)	12.75%	
Com. Eq. capitalization AY 1991 (Adopted in AY1991)	51.00%	
Wtd. cost of Common Equity for Att. Year 1991	6.50%	
Increase in Common Equity cost in Att. Year 1991	1,195	
Net-to-Gross Multiplier (Adopted in GRC)	1.712031	
Increase in Revenue Requirement	2,045	(58)

Retirement of debt

Increase in Revenue Requirement (Adopted in AY1991)	(0)

RATEBASE TRACKING

Wtd. avg. Depr.Rate Base in TY1989 (Adopted in GRC)	274,248
Wtd. avg. Depr.Rate Base in TY1989 (estimated at the time of filing for AY 1990)	274,248
Wtd. avg. Depr.Rate Base in TY1989 (recorded)	274,248
Wtd. avg. Depr.RateBase in AY1990 (Adopted in GRC)	289,891
Wtd. avg. Depr.RateBase in AY1990 (estimated at the time of filing for AY 1990)	289,891
Wtd. avg. Depr.RateBase in AY1990 (use updated est.	289,891
Wtd. avg. Depr.RateBase in AY1991 (Adopted in GRC)	308,268
Wtd. avg. Depr.RateBase in AY1991 (use updated est.	308,268

SAN DIEGO GAS & ELECTRIC COMPANY
Gas Department
REVENUE REQUIREMENTS FOR ATTRITION YEAR 1991
Thousands Of 1991$

ITEM	ATTRITION YEAR 1991	
O & M EXPENSES :		
Labor Escalation	$1,614	(47)
Non-Labor Escalation	1,265	(48)
Total O&M Expenses	2,879	
CAPITAL RELATED ITEMS :		
Book Depreciation Expenses	3,142	(49)
Ad Valorem Taxes	352	(50)
Accelerated Amortization	0	(51)
State Tax Depreciation	(141)	(52)
Federal Tax Depreciation	(757)	(53)
ITC normalized	0	(54)
Interest Synchronization	(1)	(55)
Debt cost	704	(56)
Preferred Stock cost	195	(57)
Common Equity cost	2,045	(58)
Total Capital Related Items	5,539	
OTHER AUTHORIZED ITEMS :		
Retirement of debt (Adopted in AY 1991)	(0)	
Book Depreciation exp. adj. (Adopted in AY1991)	0	
Amort. of CIMAC bal. account (Adopted in AY1990)	(0)	
Total Other Authorized Items	(0)	
TOTAL ADD'L REVENUE REQUIREMENTS ---->	$8,418	

APPENDIX C

SAN DIEGO GAS AND ELECTRIC COMPANY

Electric Department - California Jurisdiction

SUMMARY OF REVENUE CHANGES

Test Year 1989

	Revenue Element	Present rate revenues 6/ (000's of $)	Revenue change (000's of $)	Adopted Revenue 6/ (000's of $)	Average Rate 6/ (cents/Kwh)
1		(a)	(b)	(c)	(d)
2	Base Rate Revenues				
3	Base Rate Revenues	$870,018	($85,759)	$784,259	6.089 1/8/10/
4	SONGS 2&3 post-COD disallowance	0	(1,438)	(1,438)	(0.011)9/
5	SONGS 2&3 pre-COD AFUDC disallowance	0	(799)	(799)	(0.006)2/
6	Amortization of overcollection in the				
7	CLMAC balancing account	0	(3,577)	(3,577)	(0.028)
8					
9	Total Base Rate Revenues	870,018	(91,573)	778,445	6.044
10					
11	Major Additions Adjustment Clause (MAAC)				
12	SONGS 2&3 pre-COD interim rate	0	0	0	0.000 3/
13	SONGS 2&3 pre-COD amortization	(19,680)	0	(19,680)	(0.152)4/
14	SONGS 2&3 post-COD interim rate	14,631	(14,631)	0	0.000 5/
15	SONGS 2&3 post-COD amortization	0	10,876	10,876	0.084 7/
16					
17	Total MAAC	(5,050)	(3,755)	(8,804)	(0.068)
18					
19	Conservation & Load Mgmt. Programs				
20	Adjustment Clause (CALPAC) rate	0	0	0	0.000
21	Energy Cost Adjustment Clause (ECAC)	362,991	4,586	367,577	2.839 11/
22	Annual Energy Rate (AER)	32,369	187	32,556	0.251 11/
23	Electrical Revenue Adjustment Mechanism				
24	(ERAM) balancing account rate	(4,402)	(30,475)	(34,877)	(0.269)11/
25					
26	Subtotal - Revenue from retail sales	$1,255,926	($121,030)	$1,134,896	8.798
27					
28	Miscellaneous Revenues	17,005	0	17,005	
29	Non-Jurisdictional Revenues	1,445	0	1,445	
30					
31	TOTALS FOR ELECTRIC DEPARTMENT	$1,274,376	($121,030)	$1,153,346	8.908

1/ Includes revenue impact of forecasted SONGS 2&3 post-COD expenditures rather than the rate of 0.108 cents/Kwh as adopted in D.88-SONGS.

2/ Estimate of SONGS 2&3 pre-COD AFUDC disallowance as per D.88-SONGS.

3/ See D.87-12-063.

4/ Amortization of MAAC account balance including the effects of disallowed SONGS 2&3 pre-COD plant expenditures. Estimate of the effects of (a) AFUDC allocation, and (b) interest overcharged as per D.88-SONGS.

5/ Termination of SONGS 2&3 post-COD interim rate.

6/ Based on adopted GRC sales (after employee discounts) of 12,947.5 Gwh.

7/ Amortization of MAAC account balance including the effects of disallowed SONGS 2&3 post-COD plant expenditures. Estimates of the effects of interest overcharged as per D.88-SONGS.

8/ Assumes a return on equity of 12.75% and a return on rate base of 10.86%.

9/ Estimate of SONGS 2&3 post-COD disallowance from GRC revenues as per D.88-SONGS.

10/ Reflects the removal of ERAM and MAAC revenues and the correction for billing determinants previously included.

11/ Estimate. Refer D.88-ECAC.

SAN DIEGO GAS AND ELECTRIC COMPANY
Gas Department
Steam Department
SUMMARY OF REVENUE CHANGES
Test Year 1989

	Revenue Element	Present rate revenues 2/ (000's of $)	Revenue change (000's of $)	Adopted Revenue 2/ (000's of $)	Average Rate 2/ (cents/therm)
		(a)	(b)	(c)	(d)
1	Base Cost Amount				
2	Base Cost Amount	$121,823	$10,351	$132,174	12.519 3/
3	Amortization of overcollection in the				
4	CLMAC balancing account	0	(1,198)	(1,198)	(0.113)
5					
6	Subtotal	$121,823	$9,153	$130,976	12.405
7	Less: Miscellaneous sales	3,152	0	3,152	
8					
9	Subtotal - Revenue from sales	$118,671	$9,153	$127,824	12.107
10	Miscellaneous sales	3,152	0	3,152	
11	Other including fuel offset revenues	323,197	0	323,197	1/
12					
13	TOTALS FOR GAS DEPARTMENT	$445,020	$9,153	$454,173	43.016

1/ Items not addressed in 1988.
2/ Based on adopted GRC sales of 1,055,821,000 therms.
3/ Assumes a return on equity of 12.75% and a return on rate base of 10.86%.

	Revenue Element	Present rate revenues 5/ (000's of $)	Revenue change (000's of $)	Adopted Revenue 5/ (000's of $)	Average Rate 5/ ($/1000 lbs.)
		(a)	(b)	(c)	(d)
14	Base Rate Revenues				
15	Present rate Base Rate Revenues	$954	$501	$1,455	25.598 6/
16					
17	Energy Cost Adjustment Clause (ECAC)				
18	and Steam Revenue Adjustment Mechanism				
19	(SRAM) balancing account rate	270	0	270	4.750 4/
20					
21	Subtotal - Revenues from sales	$1,224	$501	$1,725	30.348
22					
23	TOTALS FOR STEAM DEPARTMENT	$1,224	$501	$1,725	30.348

4/ Unknown. SDG&E intends to file an Advice Letter requesting changes to be eff. 1/1/89.
5/ Based on adopted GRC sales of 56,840,000 lbs.
6/ Assumes a return on equity of 12.75% and a return on rate base of 10.86%.

(END OF APPENDIX C)

APPENDIX D
PAGE 1

SAN DIEGO GAS AND ELECTRIC COMPANY 1/
PROPOSED EPMC REVENUE ALLOCATION
EFFECTIVE JANUARY 1, 1989

CUSTOMER GROUP	SALES 2/ (GWH)	PRESENT RATE REV 3/ ($000's)	TOTAL MC REVS 4/ ($000's)	FULL EPMC ($000's)	(%) INC.	AVERAGE RATE ($/KWH)
RESIDENTIAL	5,136	551,147	533,596	515,828	(7)	0.100
SM/MED POWER						
GENERAL SERVICE	1,504	171,952	149,556	144,576	(16)	0.096
GS-DEMAND METERED>20 kW	2,029	181,830	168,786	163,165	(10)	0.080
LARGE POWER						
LARGE TOU > 20 kW	3,110	256,159	238,960	231,003	(10)	0.074
VERY LARGE TOU > 500 kW	910	67,861	60,100	58,099	(14)	0.064
AGRICULTURE	183	17,471	14,839	14,365	(18)	0.078
STREETLIGHTING	75	9,505	4,953	7,860	(17)	0.105
TOTAL	12,947	1,255,926	1,170,790	1,134,896	(10)	0.088

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. Facilities charges are $3.072 million for street lights. Optional TOU meter charges are $20,000 for agriculture and $1,000 for residential.
Reflects revenue requirement from Appendix C.

2/ Sales figures reflect general rate case stipulation. Sales have not been adjusted for employee discounts.

3/ Present rate revenues reflect authorized residential undercollection to coordinate baseline changes in D.88-10-062 with this general rate case. This decision terminates the undercollection, and completes implementation of baseline rate changes ordered in D.88-10-062.

4/ Based on Marginal Costs as modified by this decision.

APPENDIX D
PAGE 2
SAN DIEGO GAS AND ELECTRIC COMPANY 1/
ALLOCABLE REVENUE REQUIREMENT

CUSTOMER GROUP	ADJUSTED SALES /2 (GWH)	REVENUE REQ ($000's)	FACILITIES CHARGES ($000's)	ECAC ($000's)	AER ($000's)	MAAC ($000's)	ERAM ($000's)	BASE ($000's)
RESIDENTIAL	5,126.4	515,828.4	1.0	145,652.7	12,900.3	(3,488.6)	(13,820.0)	374,583.0
SM/MED POWER								
A	1,504.0	144,575.8		42,731.8	3,784.7	(1,023.5)	(4,054.5)	103,137.3
AD	2,029.0	163,165.5		57,648.2	5,105.9	(1,380.8)	(5,469.9)	107,262.0
GROUP TOTAL	3,533.0	307,741.3		100,380.1	8,890.6	(2,404.2)	(9,524.4)	210,399.3
LARGE POWER								
AL-TOU	3,110.0	231,002.7		88,361.7	7,826.1	(2,116.4)	(8,384.1)	145,315.3
A6-TOU	910.0	58,098.7		25,855.0	2,290.0	(619.3)	(2,453.2)	33,026.2
GROUP TOTAL	4,020.0	289,101.4		114,216.8	10,116.1	(2,735.7)	(10,837.3)	178,341.5
AGRICULTURE								
PA	175.4	13,775.8		4,983.5	441.4	(119.4)	(472.9)	8,943.2
PA-TOU	7.5	589.0	20.0	213.1	18.9	(5.1)	(20.2)	362.4
GROUP TOTAL	182.9	14,364.9		5,196.6	460.3	(124.5)	(493.1)	9,325.6
STREETLIGHTING	75.0	7,860.1	3,072.0	2,130.9	188.7	(51.0)	(202.2)	2,721.7
TOTAL	12,937.3	1,134,896.0	3,073.0	367,577.0	32,556.0	(8,804.0)	(34,877.0)	775,371.0

1/ Allocable revenue requirement equals revenue requirement from Appendix C less facilities charges.
GRC sales applied to rates for ECAC, AER and ERAM components in A.88-07-003.

2/ Sales adjusted for employee discounts.

APPENDIX F

SAN DIEGO GAS AND ELECTRIC COMPANY

ELECTRIC RATE DESIGN APPENDIX

NOTE: This rate appendix includes PUC surcharge of $.00012/kWh which is added after rate design.

Residential rates are designed based on latest total revenue requirement of $1,134,896,000, and corresponding residential revenue requirement of $515,828,000.

Other rates are designed based on prior total revenue requirement of $1,135,534,000. All rates will be designed based on single adopted revenue requirement in final decision.

APPENDIX F
PAGE 1
SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED RESIDENTIAL RATES

EFFECTIVE 01-01-89
($/KWH)

SCHEDULE	DR	DA-TOU	DU-TOU
MINIMUM BASE RATE CHARGE ($/DAY)	$0.16	$0.22	$0.22
a/			
BASELINE	$0.08160	--	--
NON-BASELINE	$0.12924	--	--
ON-PEAK ENERGY RATE			
BASELINE	--	$0.12728	$0.08797
NON-BASELINE	--	$0.20163	$0.13933
OFF-PEAK ENERGY RATE			
BASELINE	--	$0.06370	$0.04404
NON-BASELINE	--	$0.08770	$0.06973
METER CHARGE ($/DAY)	--	$0.06	$0.06

a/ The baseline energy rate is 92.9% of the System Average Rate (SAR), where the SAR is total revenue requirement from sales divided by total sales ($1,135,534 MM / 12,947 MMKWH = 0.08771 $/KWH). Baseline rate was set by D.88-10-062.

RESIDENTIAL SCHEDULES WITH REVISED DISCOUNTS:

DS $.11 per apartment per day
DT $.312 per mobile home unit per day

APPENDIX F
PAGE 4
SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED SMALL AND MEDIUM POWER RATES

EFFECTIVE 01-01-89
($/KWH)

SCHEDULE	A	AD
CUSTOMER CHARGE	$5/MONTH	$20/MONTH
DEMAND CHARGE ($/KW/MONTH)	--	$5.50
FLAT ENERGY RATE	$0.09205	$0.06202

SCHEDULE CHANGES:
(1) A and AD customers may take service under AL-TOU. Applicability restrictions deleted.
(2) AD customers may take standby service. The on-peak summer and winter rates for such customers is limited to $.67016 and $.26016 per kwh respectively.

APPENDIX F
PAGE 5
SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED LARGE POWER RATES

EFFECTIVE 01-01-89
($/KWH)

SCHEDULE	AL-TOU			A6-TOU	
VOLTAGE	SECONDARY	PRIMARY	TRANSMIS	PRIMARY	TRANSMIS
CUSTOMER CHARGE	$20.00	$20.00	$20.00	$600.00	$600.00
PEAK DEMAND CHARGE ($/KW/MONTH)					
SUMMER	$14.42	$14.42	$9.07	$17.18	$11.01
WINTER	$3.36	$3.36	$1.34	$4.01	$1.79
NON-TIME RELATED DEMAND CHARGE ($/KW/MONTH)	$3.05	$2.42	$1.02	$2.42	$1.02
SUMMER ENERGY CHARGE:					
ON-PEAK	$0.07899	$0.07392	$0.07170	$0.07392	$0.07170
MID-PEAK	$0.05112	$0.04869	$0.04724	$0.04869	$0.04724
OFF-PEAK	$0.03869	$0.03622	$0.03514	$0.03622	$0.03514
WINTER ENERGY CHARGE:					
ON-PEAK	$0.07085	$0.06626	$0.06428	$0.06626	$0.06428
SEMI-PEAK	$0.04473	$0.04153	$0.04029	$0.04153	$0.04029
OFF-PEAK	$0.03764	$0.03427	$0.03324	$0.03427	$0.03324
RATE LIMITER:					
AVERAGE	$0.16012	$0.16012	$0.16012	$0.16012	$0.16012

SCHEDULE CHANGE: Applicability of AL-TOU is expanded to include customers qualifying for service under schedule A or AD.

INTERRUPTIBLE CREDITS

	DEMAND CHARGE CREDIT ($/KW/MONTH)
I-1: OPTION A	$3.40
OPTION B	$2.27
OPTION C	
UTILITY CONTROLLED	$3.40
OTHER INTERRUPTIBLE DEMAND	$2.27

	ONE-YEAR CREDIT ($/KW/MONTH)	FIVE-YEAR CREDIT ($/KW/MONTH)
I-2: OPTION A	$5.55	$6.99
OPTION B	$5.09	$6.41
OPTION C	$4.11	$5.19
OPTION D	$3.77	$4.75

NOTE: All I-2 customers receive $.28 credit per interruption per kW.

A.87-12-003, I.88-01-006 ALJ/FSF CACD/sl

APPENDIX F

PAGE 6

SAN DIEGO GAS AND ELECTRIC COMPANY

ADOPTED LARGE POWER RATES

EFFECTIVE 01-01-89

($/KWH)

SCHEDULE	AO-TOU	A06-TOU
CUSTOMER CHARGE	$50/MONTH	$250/MONTH
PEAK DEMAND CHARGE ($/KW/MONTH):		
SUMMER	$13.00	$15.49
WINTER	$3.50	$4.17
NON-TIME RELATED DEMAND CHARGE ($/KW/MONTH)	$7.31	$7.31
ON-PEAK ENERGY RATE	$0.04537	$0.04537
SEMI-PEAK ENERGY RATE	$0.03708	$0.03708
OFF-PEAK ENERGY RATE	$0.03254	$0.03254

APPENDIX F
PAGE 7
SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED STANDY RATES

EFFECTIVE 01-01-89
($/KWH)

SCHEDULE	S		
VOLTAGE	SECONDARY	PRIMARY	TRANSMISSION
CONTRACT DEMAND CHARGE ($/KW/MONTH)	$2.44	$1.94	$0.82
RATE LIMITER:			
SUMMER ON-PEAK	$0.67012	$0.67012	$0.67012
WINTER ON-PEAK	$0.26012	$0.26012	$0.26012

SCHEDULE CHANGE: AD customers are eligible to receive standby service.

Special condition change: Customers electing to receive standby service are restricted to a single rate schedule.

APPENDIX F
PAGE 8
SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED AGRICULTURAL RATES

RATE SCHEDULE	CUSTOMER CHARGE ($/MONTH)	METER CHARGE ($/MONTH)	DEMAND CHARGE ON-PEAK ($/KW)	DEMAND CHARGE SEMI-PEAK ($/KW)	ENERGY CHARGE ($/KWH) FLAT		
PA	$8.00	--	--	--	0.07631		
					ON-PEAK	SEMI-PEAK	OFF-PEAK
PA-TOU	$8.00	$10.00	--	--	0.13620	--	0.06193
PA-T-1	$20.00	--			0.07913	0.05855	0.03809
OPTION A			$10.28 a/	$0.50			
OPTION B			$9.03	$0.50			
OPTION C			$8.83	$0.50			
OPTION D			$9.21	$0.50			
OPTION E			$9.02	$0.50			
OPTION F			$8.63	$0.50			

a/ On-peak demand charge is applied to contribution to monthly peak.

APPENDIX F
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SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED EXPERIMENTAL RATES

EFFECTIVE 01-01-89
($/KWH)

SCHEDULE	AE-1	R-TOU-1	R-TOU-2	AE-2	R-TOU-3	R-TOU-4
	(closed)	(closed)	(closed)	(new)	(new)	(new)
CUSTOMER CHARGE	$600.00	$600.00	$600.00	$600.00	$600.00	$600.00
MAXIMUM DEMAND CHARGE ($/KW/MONTH)						
SECONDARY	--	--	--	$3.05	$3.05	$3.05
PRIMARY	--	--	--	$2.42	$2.42	$2.42
TRANSMISSION	--	--	--	$1.02	$1.02	$1.02
MINIMUM CONTRACT DEMAND ($/KW/MONTH)	$13.75	$13.75	$13.75	$12.15	$12.15	$12.15
ENERGY CHARGE:						
SUPER-PEAK	--	$0.94492	$0.49492	--	$1.05638	$0.41719
ON-PEAK	$8.29148	$0.29661	$0.13571	$3.86426	$0.09159	$0.07451
MID-PEAK	$0.05173	$0.04647	$0.03451	$0.06459	$0.04694	$0.04293
OFF-PEAK	$0.03100	$0.03100	$0.03100	$0.03411	$0.03411	$0.03411

SCHEDULES AE-1, R-TOU-1 AND R-TOU-2 ARE CLOSED TO NEW CUSTOMERS BY THIS DECISION.

SCHEDULE CHANGES TO PG-QF:

Closed to new customers with generation facilities above 20 kW on July 1, 1989.

Special condition changes:

Conditions related to energy netting to be eliminated for all customers on July 1, 1989.

APPENDIX F
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SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED STREET LIGHTING RATES
Effective 1/1/89

Rate Schedule / Watts		Lumens	Rate ($/Lamp) (2)
LS-1, Mercury Vapor, Class A			
	175	7,000	$9.34
	250	10,000	$12.64
	400	20,000	$17.45
	700	35,000	$33.80
LS-1, Mercury Vapor, Class C, 1-Lamp			
	175	7,000	$17.33
	250	10,000	$23.02
	400	20,000	$27.82
LS-1, Mercury Vapor, Class C, 2-Lamp			
	175	7,000	$26.62
	400	20,000	$45.81
LS-1, HPSV, Class A			
	70	5,800	$6.14
	100	9,500	$7.16
	150	16,000	$8.54
	200	22,000	$10.30
	250	30,000	$13.00
	400	50,000	$16.43
	1,000	140,000	$34.48
LS-1, HPSV, Class B, 1-Lamp			
	70	5,800	$6.75
	100	9,500	$7.77
	150	16,000	$9.16
	200	22,000	$11.09
	250	30,000	$13.79
	400	50,000	$17.31
	1,000	140,000	$35.42
LS-1, HPSV, Class B, 2-Lamp			
	70	5,800	$11.82
	100	9,500	$13.85
	150	16,000	$16.67
	200	22,000	$20.37
	250	30,000	$25.77
	400	50,000	$32.57
	1,000	140,000	$68.77
LS-1, HPSV, Class C, 1-Lamp			
	70	5,800	$13.92
	100	9,500	$14.94
	150	16,000	$16.34
	200	22,000	$20.66
	250	30,000	$23.36
	400	50,000	$28.11
	1,000	140,000	$47.03
LS-1, HPSV, Class C, 2-Lamp			
	70	5,800	$19.81
	100	9,500	$21.85
	150	16,000	$24.63

SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED STREET LIGHTING RATES

Effective 1/1/89

Rate Schedule	Watts	Lumens	Rate ($/Lamp) (2)
	200	22,000	$31.48
	250	30,000	$36.89
	400	50,000	$42.78
	1,000	140,000	$80.15
LS-1, LPSV, Class A			
	35	4,800	$7.36
	55	8,000	$7.99
	90	13,500	$9.94
	135	22,500	$12.34
	180	33,000	$13.43
LS-1, LPSV. Class B, 1-Lamp			
	35	4,800	$7.99
	55	8,000	$8.71
	90	13,500	$10.67
	135	22,500	$13.24
	180	33,000	$14.33
LS-1, LPSV, Class B, 2-Lamp			
	35	4,800	$14.28
	55	8,000	$15.64
	90	13,500	$19.54
	135	22,500	$24.56
	180	33,000	$26.75
LS-1, LPSV, Class C, 1-Lamp			
	35	4,800	$13.15
	55	8,000	$13.88
	90	13,500	$17.85
	135	22,500	$22.80
	180	33,000	$23.90
LS-1, LPSV, Class C, 2-Lamp			
	35	4,800	$22.28
	55	8,000	$23.64
	90	13,500	$27.56
	135	22,500	$35.68
	180	33,000	$37.86
LS-1, Facilities and Rates, Class A			
Center Suspension			$4.30
Non-Standard Wood Pole			
30-foot			$2.16
35-foot			$2.42
Recator Ballast Discount			
	175		($0.88)
	250		($0.35)
LS-1, Facilities and Rates, Class B & C			
Other app. inst.			$0.00

LS-2, Mercury Vapor, Rate A

APPENDIX F
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SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED STREETLIGHTING RATES
Effective 1/1/89

Rate Schedule Watts	Lumens	Rate ($/Lamp) (2)
175	7,000	$5.27
250	10,000	$7.26
400	20,000	$11.44
700	35,000	$19.39
1,000	55,000	$27.39
LS-2, Mercury Vapor, Rate B, Energy & Lmt Maintenance		
175	7,000	$5.76
250	10,000	$7.80
400	20,000	$11.31
LS-2, Mercury Vapor, Surcharge for series service		
175	7,000	$0.36
250	10,000	$0.45
400	20,000	$0.65
700	35,000	$1.19
LS-2, HPSV, Rate A		
50	3,300	$1.44
70	5,800	$2.31
100	9,500	$3.51
150	16,000	$4.80
200	22,000	$6.12
250	30,000	$7.78
310	37,000	$9.52
400	50,000	$11.83
1,000	140,000	$27.39
LS-2, HPSV, Rate B, Energy & Lmt Maintenance		
50	3,300	$2.06
70	5,800	$3.12
100	9,500	$4.11
150	16,000	$5.42
200	22,000	$6.74
250	30,000	$8.40
310	37,000	$10.13
400	50,000	$12.46
1,000	140,000	$28.17
LS-2, HPSV, Reduction for 120-volt Reactor Ballast		
70	5,800	($0.36)
100	9,500	($0.48)
150	16,000	($0.44)
LS-2, HPSV, Surcharge for Series Service		
50	3,300	$0.40
70	5,800	($0.20)
100	9,500	($0.21)
150	16,000	$0.02
200	22,000	$0.43
LS-2, LPSV, Rate A		
35	4,800	$1.62
55	8,000	$2.12
90	13,500	$3.30

SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED STREET LIGHTING RATES
Effective 1/1/89

Rate Schedule	Watts	Lumens	Rate ($/Lamp) (2)
	135	22,500	$4.97
	180	33,000	$5.67
LS-2, LPSV, Surcharge for series service			
	35	4,800	($0.21)
	55	8,000	($0.12)
	90	13,500	$0.40
	135	22,500	$0.72
	180	33,000	$0.46
LS-2, Incandescent Lamps, Rate A, Energy Only			
		1,000	$1.76
		2,500	$3.91
		4,000	$5.91
		6,000	$8.68
		10,000	$14.67
LS-2, Incandescent Lamps, Rate B, Energy and Limited Ma			
		4,000	$7.65
		6,000	$10.45
LS-3			
Energy Charge			$0.073
Minimum Charge			$5.88
OL-1, Mercury Vapor, Rate A, SL Luminaire			
	175	7,000	$9.37
	400	20,000	$19.12
OL-1, HPSV, Rate A, Street Light Luminaire			
	100	9,500	$7.87
	150	16,000	$9.26
	250	30,000	$14.16
	400	50,000	$17.36
	1,000	140,000	$36.00
OL-1, HPSV, Rate B, Directional Luminaire			
	250	30,000	$17.06
	400	50,000	$21.38
	1,000	140,000	$38.51
OL-1, Pole			
30 ft wood pole			$2.85
35 ft wood pole			$3.20
DWL, facilities Charges			
% of Util invst.			$0.0228
DWL, Energy and Lamp Maintance Charge			

SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED STREET LIGHTING RATES
Effective 1/1/89

Rate Schedule Watts	Lumens	Rate ($/Lamp) (2)
50 Watt HPSV		$3.03
100 Watt HPSV		$0.00
100 Watt M. Vapor		$0.00
DWL, Min. Charge		$136.42

(END OF APPENDIX F)

A.87-12-003,I.88-01-006 ALJ/FSF
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APPENDIX G
PAGE 2

SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED GAS REVENUE ALLOCATION 1/ 2/
Test Year 1989

	CUSTOMER CLASS	SALES (M THERMS)	REVENUE AT PRESENT RATES: BASE ($000's)	REVENUE AT PRESENT RATES: TOTAL ($000's)	REVENUE AT ADOPTED RATES: BASE ($000's)	REVENUE AT ADOPTED RATES: TOTAL ($000's)	REVENUE CHANGES TO BE REFLECTED IN RATES: Amt ($ Thousands) BASE	Amt ($ Thousands) TOTAL	% INC TOTAL
1	CORE: 1/	423641	98296	240678	98296	240678	0	0	0
	NONCORE: 2/								
	o RETAIL								
	Transmission:								
	- Cogen	95500	2662	10948	2864	11150	202	202	1.85%
	- Other	32563	3660	7096	3999	7435	339	339	4.77%
4	WACOG	128063	0	25788	0	25788	0	0	0.00%
	o UTILITY ELECTRIC GENERATION								
5	Transmiss	504117	14051	57793	15112	58854	1061	1061	1.84%
6	WACOG	504117	0	99563	0	99563	0	0	0.00%
7	NONCORE TOTAL		20373	201188	21975	202790	1602	1602	0.80%

1/ CORE REVENUE ALLOCATION. There is no change in core (residential and commercial) rates. The margin change allocable to core customers is to be reflected in core balancing account to be addressed in SDG&E's next ACAP. The adopted increase in authorized margin (Base Cost Amount) is $12.528 million. See Appendix A for detail. The core/noncore split is 82.5% to core and 17.5% to noncore, as reflected in SDG&E's May 1, 1988 compliance filing. Based on these allocation factors, core and noncore customer's authorized increase in margins are:

CORE: 10335.60 NONCORE: 2192.40

2/ NONCORE REVENUE ALLOCATION assumes allocation factors used in SDG&E's May 1, 1988 compliance filing for initial allocation. Cogeneration and UEG rates are then equalized as required by D. 87-12-039, resulting in final revenue allocation to these classes. (Noncore's May 1 allocation share is 17.5%: UEG, 8%; cogeneration, 5.8%; other, 3.7%).

[Noncore change in margin of $2.192 million includes $1.602 million change in rates over present rates (assuming GRC stipulated sales), and remaining $590 thousand revenue change (2192-1602) due to increased sales in test year.]

SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED NONCORE GAS RATES
EFFECTIVE 01-01-89

SCHEDULE

UEG/INTERDEPT
SCHEDULE GTUEG

(Thousands of Dollars)

Monthly Demand Charges:				
Jan	2835	July	4563
Feb	2434	Aug	4682
Mar	2551	Sept	3973
April	2455	Oct	3630
May	3821	Nov	3286
June	3775	Dec	2577

		(Cents/Therm)
Volumetric Charges:	Tier I	6.168
	Tier II	3.047

COGENERATION
SCHEDULE GTCG

Customer Charge	No Change
	(Cents/Therm)
Volumetric Demand Charge	11.415 1/

OTHER NONCORE TRANSMISSION
SCHEDULE GTNC

Customer Charge	No Change	
Default Rates:		(Cents/Therm)
Average Demand Charge (D-1)		6.919
Seasonal Peak Demand Charge (D-2):		
Summer....................................		4.188
Winter....................................		7.360
Volumetric Charge..............................		7.325

1/ Actual volumetric demand charge for cogenerators varies monthly based on recorded UEG data based on D. 87-12-039.

(END OF APPENDIX G)

APPENDIX H

SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED STEAM REVENUE ALLOCATION AND RATE DESIGN
Test Year 1989

REVENUE ALLOCATION

SCHEDULE	SALES 1/ (1000 LB) & CUST MO	PRESENT RATE REVENUES ($000's)	ADOPTED RATE REVENUES ($000's)
SCHEDULE 1			
Service ($/MO)	285	4	9
Commodity ($/1000 LB)	50214	1076	1514
Subtotal		1080	1523
SCHEDULE 2			
Service ($/MO)	12	0 2/	0
Commodity ($/1000 LB)	6626	143	202
Subtotal		144	202
TOTAL		1224	1725

1/ GRC stipulated sales
2/ Zero only when rounded.

RATE DESIGN

SCHEDULE	SALES (1000 LB) & CUST MO	PRESENT RATES ($)	ADOPTED RATES ($)
SCHEDULE 1			
Service ($/MO)	285	15	30.00
Commodity ($/1000 LB)	50214	21.428	30.154
SCHEDULE 2			
Service ($/MO)	12	15.15	30.30
Commodity ($/1000 LB)	6626	21.642	30.455

(END OF APPENDIX H)