C

Re San Diego Gas and Electric Company
Decision 85-12-108
Application 84-12-015
I. 85-02-010

California Public Utilities Commission
December 20, 1985

APPLICATION by a combination electric, gas, and steam utility for authority to increase rates; granted as modified in the amount of $9.597 million for electric service, $3.272 million for gas service, and $1.445 million for steam service, with an authorized rate of return on common equity of 15%.

P.U.R. Headnote and Classification

1.
EXPENSES

s19 - Nonrecurring extraordinary expenses - Amortization.
Ca.P.U.C. 1985
Because of their nonrecurring nature, one-time extraordinary expenses occurring during the test year should not be used in setting rates, but the expenses may be recognized through amortization over the rate-effective period.

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P.U.R. Headnote and Classification

2.
EXPENSES

s58 - Franchise fees - Basis for calculation - Interdepartmental sales.
Ca.P.U.C. 1985
The commission refused to recompute a utility's franchise fee expense to include sales of gas to its electric department where interdepartmental sales traditionally had been excluded from franchise fee calculations, despite a pending case seeking to include such interdepartmental sales.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

3.
EXPENSES

s19 - Customer account expenses - Transfer of funds from abolished conservation programs.
Ca.P.U.C. 1985
Despite pending elimination of a utility's residential conservation service (RCS) program, the utility was not allowed to transfer remaining funds to customer account expenses to cover expected high-bill inquiries, even though such inquiries previously had been charged to the RCS program.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

4.
EXPENSES

s118 - Uncollectibles - Bad debt customer identification program.
Ca.P.U.C. 1985
A utility's uncollectibles allowance was reduced where the utility appeared to have been having improved customer payment records in recent years; accordingly, a proposal to initiate a “bad debt match” program, which would identify payment risk customers moving within or between service territories, was rejected as premature, especially since no other utility had yet agreed to participate in the program.

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P.U.R. Headnote and Classification

5.
EXPENSES

s76 - Adminstrative and general expenses - Growth rate.
Ca.P.U.C. 1985
A utility's administrative and general expenses may increase in line with economic growth rates and market price increases, and are not limited to increases reflecting the mere growth rate in customers and sales.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

6.

EXPENSES

s105 - Salaries - Bonuses.
Ca.P.U.C. 1985
Because bonuses should be awarded to employees only in those years when a company does better than in prior years, and not as a matter of routine, bonuses should not be included as a standard component of salary expense calculations.

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P.U.R. Headnote and Classification

7.
EXPENSES

s63 - Legal fees - Out-of-state counsel.
Ca.P.U.C. 1985
A utility's legal fee expense will not be disallowed merely because the utility has chosen counsel located out-of-state.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

8.
EXPENSES

s28 - Audits - Outside versus in-house audits - Conflicts of interest.
Ca.P.U.C. 1985
A utility's auditing expense was not reduced despite the fact that the original outside accounting firm appointed by commission staff to conduct the outside portion of the audit turned out to have a conflict of interest, where the utility had not had the primary duty of notifying the staff of the potential conflict; it also was deemed reasonable for the utility to claim all of its in-house auditing expenses as a separate item, since the utility had set up a separate staff to perform the mandated audit.

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P.U.R. Headnote and Classification

9.
EXPENSES

s49 - Employee pensions and benefits - Health care - Participants versus employees.
Ca.P.U.C. 1985
A utility's expense allowances for employee pensions and health care plans should be based not just on the number of employees the utility has, but also on how many dependents and total participants are involved.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

10.
EXPENSES

s49 - Employee pensions - Retirement and savings plans.
Ca.P.U.C. 1985
Although not disallowing outright a utility's expenses associated with a matching contribution employee savings plan, the commission found that the expenses were out of control, and therefore, it adopted a cap on the expenses, so that shareholders rather than ratepayers would be responsible for any costs incurred over and above the c

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P.U.R. Headnote and Classification

11.
EXPENSES

s89 - Regulatory expenses - Increasing complexity - Longer rate case cycles.
Ca.P.U.C. 1985
Increased regulatory expenses are justified in spite of longer rate case cycles and rate-effective periods because of the increasing complexities involved in the regulation of utilities.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

12.
VALUATION

s294 - Working capital - Cash - Minimum bank balances - Banking fees.
Ca.P.U.C. 1985

Because a utility had to maintain a certain minimum bank balance in order to provide for overdraft protection, a portion of the interest accrued on that account was ordered applied to banking fees, although it was generally agreed that it would be more economical to expense than to capitalize banking costs.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

13.
EXPENSES

s48 - Dues - Ratepayer benefits.
Ca.P.U.C. 1985
Although not convinced by a utility's presentation of the ratepayer benefits resulting from payment of dues to the Edison Electric Institute and the American Gas Association, the commission allowed the utility to recover 75% of the dues through rates, in order to assure consistency between utilities, as a similarly situated utility had recently been allowed to recoup 75% of its dues costs.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

14.
EXPENSES

s119.1 - Research, development, and demonstration.
Ca.P.U.C. 1985
The commission approved the bulk of a combination gas and electric utility's proposed research budget, except for travel-related expenses, a duplicative energy management cooperative project, and the Heber project.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

15.
EXPENSES

s122 - Electric utility - Purchased power - Cogeneration.
Ca.P.U.C. 1985
An electric utility's allowance for costs associated with the purchase of cogeneration power was increased in view of the growing importance of the cogeneration industry.

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P.U.R. Headnote and Classification

16.
EXPENSES

s122 - Electric utility - Commodity costs - Fuel handling.
Ca.P.U.C. 1985
Disappointed with an electric utility's showing with respect to its fuel handling expenses, the commission said that only the company's barge operations appeared reasonable on their face, but that at least one-half of the company's remaining fixed expenses should actually vary with the amount of its oil burn.

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P.U.R. Headnote and Classification

17.
EXPENSES

s120 - Electric utility - Transmission costs - Factors.
Ca.P.U.C. 1985
In determining an electric utility's transmission costs, operations should be normalized and overhead line maintenance costs increased if more reliance is being placed on purchased power.

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P.U.R. Headnote and Classification

18.
AUTOMATIC ADJUSTMENT CLAUSES

s16 - Energy cost clauses - Fixed costs - Wheeling.
Ca.P.U.C. 1985
The commission abandoned use of a deferred account for fixed wheeling costs, finding that an electric utility's increasing reliance on purchased power dictated that fixed wheeling costs be treated in the utility's energy cost adjustment clause.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

19.
EXPENSES

s120 - Electric utility - Distribution costs - Factors.
Ca.P.U.C. 1985
An electric utility's proposed distribution expense allowance was reduced to back out rapidly escalating costs associated with an experimental data base map management system and to eliminate overhead line maintenance functions that would not actually be needed until 1993.

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P.U.R. Headnote and Classification

20.
VALUATION

s213 - Property included or excluded - Plant held for future use - Plant easily restored to service.
Ca.P.U.C. 1985
With respect to two out-of-service generating plants of an electric utility, the last one taken out of service and stored, which also would be the quickest and most economical to restore to service, was included in rate base as plant held for future use, but the other plant was removed from rate base entirely as its reactivation was doubtful.

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P.U.R. Headnote and Classification

21.
VALUATION

s280 - Electric utility property - Line capacitors - Factors.
Ca.P.U.C. 1985
An electric utility was conditionally authorized to include new line capacitors in rate base, as such inclusion would allow the utility to obtain additional economy energy and would help assure the cost-effectiveness of a power link interconnection project.

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P.U.R. Headnote and Classification

22.
VALUATION

s202 - Property included or excluded - Abandoned or retired plant - Amortization.
Ca.P.U.C. 1985
A gas utility's retired liquefied natural gas facility was removed from rate base, with the undepreciated portion of the plant being amortized over a five-year period.

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P.U.R. Headnote and Classification

23.
VALUATION

s213 - Property included or excluded - Plant held for future use - Plans and time frames.
Ca.P.U.C. 1985
Property may only be included in rate base as plant held for future use if the owning utility has definite plans for the use of the property within a reasonable period of time, although the commission declined to adopt ten years as a maximum period of consideration.

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P.U.R. Headnote and Classification

24.
CONSERVATION

s1 - Program policy - Demand-side projects.
Ca.P.U.C. 1985
Taking note of the fact that a combination electric and gas utility's marginal costs of electric service were equal to its average costs, the commission adopted a policy with respect to conservation and load management programs of staying the course - i.e., encouraging cost-effective, demand-side programs.

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P.U.R. Headnote and Classification

25.
CONSERVATION

s1 - Program policy - Reallocation of funds - Management flexibility.
Ca.P.U.C. 1985
A combination gas and electric utility was given discretion to reallocate conservation funds among various programs up to a limit of $500,000.

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P.U.R. Headnote and Classification

26.
CONSERVATION

s1 - Program budget - Program modifications.
Ca.P.U.C. 1985
A combination gas and electric utility was granted a 1986 budget of $16.5 million for conservation and load management programs, subject to the following changes in its programs: (1) reduction of advertising expenses associated with solar heating programs; (2) implementation of appliance incentive programs; (3) retention of direct weatherization assistance for low-income and elderly customers, despite the program's noncost-effectiveness; (4) institution of an energy-efficient refrigerator rebate project, but only for low-income households; (5) initiation of incentives for multifamily dwelling weatherization projects; (6) provision of funds for master meter conversions of multifamily dwellings; (7) increases in rebate funding for installation by commercial customers of peak-shift or load reduction equipment; (8) reductions in administrative costs for residential customer audit programs being phased out, but retention of funds related to nonresidential audits; (9) reduction of general conservation advertising expenses, due to saturation of market and overall customer awareness of conservation needs; (10) disallowance of consulting fees associated with a new load management data base system; (11) increases in funding for residential air-conditioning peak-shift programs, but elimination of funding for residential water heating peak-shift programs; and (12) implementation of a group load curtailment program and a community energy management program.

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P.U.R. Headnote and Classification

27.
CONSERVATION

s1 - Load management - Goals - Penalties for nonattainment.
Ca.P.U.C. 1985
Although finding that a combination gas and electric utility merely went through the motions of complying with conservation and load management directives, but appeared disinterested in developing innovative conservation measures of its own, the commission declined to institute a schedule of penalties for the utility when it fails to meet established load management goals; however, the commission urged the utility to challenge itself through the setting of more stringent load management goals, particularly with respect to the embracement of time-of-use principles.

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P.U.R. Headnote and Classification

28.
CONSERVATION

s1 - Electric utility - Special programs.
Ca.P.U.C. 1985
Reduced or historically averaged costs were used in determining an electric utility's budget for conservation projects associated with voltage regulation and conversion of streetlighting equipment, where those projects were largely completed already.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

29.
EXPENSES

s106 - Savings in operation - Merger of employee functions.
Ca.P.U.C. 1985
Although it was shown that a natural gas distribution utility could save money and improve efficiency at the same time by merging the functions of its gas servicemen and turn-on metermen, only one-third of the expected savings from such a merger was imputed for test-year purposes, where the utility could not effectuate such a change until it was ratified through labor negotiations.

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P.U.R. Headnote and Classification

30.
RETURN

s26.1 - Capital structure - Components - Equity - Capital leases.
Ca.P.U.C. 1985
A combination gas and electric utility's capital structure was set so as to reflect the utility's increasing proportion of common equity while excluding nuclear fuel and other property leases, with the commission declining to establish a formula under which any increase in the equity component of capital structure would automatically lead to a decrease in the utility's return on equity.

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P.U.R. Headnote and Classification

31.
RETURN

s26.4 - Cost of equity - Calculation methods - Risk factors.
Ca.P.U.C. 1985
A combination gas and electric utility's authorized rate of return on common equity was reduced from its previously authorized rate of 16% to 15%, in view of improved capital markets, decreasing inflation rates, and a demonstrated reduction in the financial risks faced by the utility with respect to nuclear construction and purchased power practices; the 15% figure was calculated after consideration of comparable earnings of other utilities and a multifaceted discounted cash flow method, with lesser emphasis placed on risk premium methods and capital asset pricing methods, so that more than just short-term data from a volatile market period would be evaluated.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

32.
RATES

s262 - Cost elements - Marginal costs - Components.
Ca.P.U.C. 1985
For revenue allocation and rate design purposes, the commission reaffirmed its reliance on marginal costs as opposed to embedded costs.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

33.
RATES

s262 - Cost elements - Marginal costs - Energy components.
Ca.P.U.C. 1985
Marginal energy costs reflect those changes in variable costs resulting from changes in utility systems necessary to meet small changes in load; the primary components of marginal energy costs are fuel, and operation and maintenance expenses, with administrative and general expenses being excluded and with only short-term, not long-term, energy prices recognized.

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P.U.R. Headnote and Classification

34.
RATES

s264 - Cost elements - Marginal costs - Customer costs.
Ca.P.U.C. 1985
Finding no consensus on the proper calculation of marginal customer costs, the commission adopted use of a decremental customer cost analysis, although it noted that certain customer costs actually were accounted for as being distribution-related.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

35.
COGENERATION

s27 - Rates - Avoided costs - Capacity payments - Factors and methods.
Ca.P.U.C. 1985
In determining avoided costs to be used as a basis for payments for purchases of capacity from qualifying cogeneration and small power production facilities (QFs), a shortage approach was employed premised on a “probability of need” factor which in turn was based on an annual

"loss of load probability" (LOLP) factor; in addition, it was held that system reliability should be based not on reserve margin, but on LOLP standards, with measurement of system reliability being the same whether for resource planning, cost analysis, or QF payment purposes, and with the value of additional QF capacity being priced anywhere from zero to more than the cost of a combustion turbine.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

36.
RATES

s264 - Cost elements - Marginal costs - Customer costs.
Ca.P.U.C. 1985
Although adopting marginal costs as the proper basis for allocations of revenue increases, the commission declined to include marginal customer costs in such allocations in the instant proceeding, not because such inclusion would be improper, but because marginal customer costs remained ill-defined and difficult to quantify; the commission said that it hoped such quantification problems could be resolved in the near future, in which case it would reconsider inclusion of marginal customer costs.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

37.
RATES

s362 - Electric rate design - Streetlighting - Marginal costs.
Ca.P.U.C. 1985
No part of an authorized electric rate increase was allocated to streetlighting services where it appeared that streetlighting rates already produced revenue far in excess of marginal costs of service.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

38.
APPORTIONMENT

s4 - Methods and bases - Equal percentage change.
Ca.P.U.C. 1985
A rate increase granted a combination electric and gas utility was ordered allocated on an equal percentage basis in order to preserve customer class relationships until such time as the commission reviewed marginal cost principles with respect to customer classifications.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

39.
RATES

s321 - Electric rate design - Stability in structure - Demand-side management.
Ca.P.U.C. 1985
Wanting to encourage stability in rate structure as well as cooperation in rate design, the commission ordered an electric utility to make no major changes in its rate structure except to implement demand-side management programs and emphasize time-of-use pricing principles.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

40.
RATES

s336 - Electric rate design - Special charges - Customer charges.
Ca.P.U.C. 1985
The commission refused to reinstate a customer charge as a separate item of an electric utility's bills, where such a charge had created confusion and anger in the past and had already been rolled into the utility's development of baseline rates.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

41.
RATES

s321 - Electric rate design - Baseline rates - Limit.
Ca.P.U.C. 1985
An electric utility was ordered to recompute certain of its

baseline rates where it appeared that baseline rates for certain classes exceeded the ceiling of 85% of system average rates.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

42.
RATES

s337 - Electric rate design - Special charges - Submetering discounts.
Ca.P.U.C. 1985
An electric utility was authorized to modify its submetering discount to increase it by a standard escalation factor and then reduce it by a diversity factor.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

43.
RATES

s326 - Electric rate design - Time-of-use rates.
Ca.P.U.C. 1985
The commission expressed disappointment over an electric utility's apparent lack of interest in and commitment to an experimental voluntary residential time-of-use tariff.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

44.
RATES

s339 - Electric rate design - Classes of service - Commercial, industrial, and agricultural customers - Allocation of increase.
Ca.P.U.C. 1985
Where an electric utility's rates for nontime-of-use commercial, industrial, and agricultural customers were being decreased rather than increased, the decrease was applied to commodity charges alone, thus effectively increasing fixed charges in proportion to total charges; customer and demand charges remained unchanged for those classes.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

45.
RATES

s326 - Electric rate design - Time-of-use rates - Industrial customers.
Ca.P.U.C. 1985
With respect to electric time-of-day rates for industrial customers, an authorized rate decrease was ordered applied to commodity charges, with customer and demand charges being held constant, despite a showing that demand costs do vary by time of use; the decrease in commodity charges was found to be appropriate for bringing commodity charges more in line with marginal costs.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

46.
RATES

s342 - Electric rate design - Standby service - Components.
Ca.P.U.C. 1985
An electric utility's rates for standby service were both increased and restructured, to allow pricing according to avoided cost principles and to provide incentives such as demand charge waivers to customers who operate efficiently.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

47.
RATES

s392 - Heating service - Steam rates.
Ca.P.U.C. 1985
A utility was allowed to increase its steam rates by 100% to reflect the full cost of steam; it also was authorized to close steam service to new customers and phase out old ones.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

48.
AUTOMATIC ADJUSTMENT CLAUSES

s13 - Energy cost clauses - Purchased power - Transmission interconnection project.
Ca.P.U.C. 1985
In conjunction with energy cost adjustment clause/annual energy rate mechanisms, balancing account treatment was given an electric utility's costs of purchased power made pursuant to a firm, relatively expensive, long-term agreement for capacity under the Southwest Power Link (SWPL), despite a showing that the agreement was not cost-effective and that savings purported to result from the transaction were in fact nonexistent; because of the utility's lack of experience at purchasing power as of the time it entered into the long-term arrangement, the commission determined that the utility should not be penalized for having agreed to the transaction, but an avoided cost cap was placed on SWPL costs as an incentive for the utility to make the purchases as cost-effective as possible, with any costs exceeding avoided costs being deferred in the balancing account; the commission warned, however, that any costs remaining in the balancing account after five years would be rebuttably presumed to be unreasonable, and that such treatment was not to be taken as precedent and would not be available to other utilities, as the removal of risk associated with ownership of generating plant should not be replaced with the prospect of uneconomic power purchases.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

i.
EXPENSES

s9 - Ascertainment - Problems - Base Creep.
Ca.P.U.C. 1985
Discussion by the commission of the problem of “base creep” in predicting future utility expenses.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

ii.
INTERCORPORATE RELATIONS

s14.2 - Affiliate arrangements - Research functions - Plans for diversification.
Ca.P.U.C. 1985
Discussion by the commission of the usefulness of certain utility research endeavors with respect to unregulated affiliates that would be formed under the utility's plan for diversification and reorganization.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

iii.
REVENUES

s15 - Sales of property - Allocation of gain.
Ca.P.U.C. 1985
Statement by the commission reaffirming its position on the allocation between ratepayers and shareholders of any gain or loss incurred by a utility in the sale of property or assets, and holding that an equitable sharing, after consideration of proportionate risks, is appropriate.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

iv.
ELECTRICITY

s4 - Operating practices and efficiency - Resource planning.
Ca.P.U.C. 1985
Discussion by the commission of an electric utility's efforts at resource planning, holding the utility responsible for (1) developing comprehensive least-cost resource plans, (2) assuring system reliability, (3) considering value as well as costs of reliability, energy, and capacity, and (4) proposing standards for cost-benefit analyses to test the cost-effectiveness of plans.

Re San Diego Gas and Electric Company

(Appearances are listed in Appendix A.)

By the COMMISSION:

OPINION

Summary of Decision

The decision authorizes San Diego Gas and Electric Company (SDG&E) to recover through its rates a $9,597,000 increase in its electric department revenue requirement, a $3,272,000 increase in its gas department revenue requirement, and a $1,445,000 increase in its steam department revenue requirement.

SDG&E had originally requested $339,962,000 for the electric department (including all nuclear related expenses), $27,447,000 for the gas department, and $1,530,000 for the steam department. After our Public Staff Division (Staff) and the company stipulated to a number of expense items, and the nuclear related expenses were shifted to SDG&E's MAAC proceeding and the SONGS I OII, SDG&E's final request was $55,418,000 for the electric department, $21,720,000, for the gas department, and $1,487,000 for the steam department. Staff's final recommendations were $2,003,000 (electric), $2,667,000 (gas), and $1,450,000 (steam).

The adopted electric and gas revenue increases in this case represent a 1.5% and 2.9% increase, respectively, over current revenue requirements. Because the company has experienced an increase of sales of roughly 10% since its last general rate case, the increased revenue requirement can be recovered from a larger customer base, with the result that the actual rate charged per unit of energy can decrease.

This decision also implements the effects of the 1984 and 1985 Energy Cost Adjustment Clause (ECAC) offset cases (Applications (A.) 84-07-027 and 85-06-064). The gas revenue requirement developed in this case is being implemented through the 1985 Consolidated Adjustment Mechanism (CAM) offset case (A.85-09-045).

The application of the rates resulting from the implementation of the revenue requirement increase in this decision in combination with the revenue requirement effects of the above-mentioned offset cases to forecasted sales will produce revenues which are $120 million less than the revenues which would result from the application of present rates to forecasted sales. A typical residential customer's electric bill for 400 kWh will decrease from $48.66 to $45.05 (-.7.3%).

The decision provides SDG&E an opportunity to earn a 15.00% return on equity as opposed to the presently authorized 16.00% and the requested 16.50%.

The decision allocates the entire electric revenue requirement on the basis of the equal percentage of the marginal cost (100% EPMC) which produces substantial reductions for the industrial classes. For residential customers, the baseline rates are set at 85% of the system average rate including the minimum bill revenues. For the TOU industrial rates, any changes to the rate structure were kept to a minimum.

I. *Introduction*

This application was filed on December 17, 1984. The original application requested recovery of all the expenses associated with both SONGS I and SONGS II. During the course of the hearings, the rate base expenses associated with the nuclear plants were deferred to other proceedings which reduced the request substantially. Also, the staff and the company came to agreement on many issues so that at the time of the final comparison exhibit was submitted the company request was $78,625,000 for the combined departments.

Public hearings were held in the San Diego area during the period March - June, 1985. Update hearing were held in San Francisco on September 24, 1985, and oral argument was held before the Commission en banc on October 31, 1985.

In addition to the Commission staff (PSD) and the company, the following parties presented testimony and/or filed briefs in this proceeding:

1. Federal Executive Agencies 2. Western Mobilehome Association

3. California/Nevada Community Action Association

4. City of San Diego

5. California City - County Streetlight Association

6. Association California Water Agencies

7. Utility Consumers' Action Network

8. Insulation Contractors Association

9. San Diego Mineral Products Industry Coalition

10. Kelco Division of Merck & Company

11. Independent Power Corporation

12. Independent Energy Producers Association

13. California Energy Commission

14. California Department of General Services

15. California Manufacturers Association

Before starting our discussion of the particulars of the case, we wish to begin with a few general comments on our desire to provide policies which foster a positive business climate in the state and fairness to all ratepayers. SDG&E is in a particularly difficult position because in recent times it has had the second highest rates in the nation. Because energy costs are an important part of overhead, this does not bode well for the business climate in SDG&E's service territory. We feel that this decision offers a number of rate schedule and demand side management options to businesses and residences alike, directed both toward providing correct price signals and toward offering ways to reduce a customer's energy costs.

Preliminary Issues

During the hearings concerning operating expenses, several issues were often repeated. By dealing with those issues here at the beginning, we hope to avoid the need to discuss an issue more than once.

1. *One-Time Extraordinary Expenses in Test Year*

[1] The first such issue deals with the fact that expense in many accounts were characterized by the staff and/or others as one-time expenses. Although the staff recognizes the expenses as legitimate, the issue is whether or not the expense should be included totally (100%) in the test year expense estimates. The staff position is generally that the one-time expense will not be incurred in the subsequent attrition years and to include them totally in the test year estimates would allow recovery for the same expense three times before the next general rate case. The staff also argues that it would be too difficult to track these items to make sure that they were excluded in the attrition year filings. The staff solution is to recognize the expense but to amortize the expense over the three years until the next general rate case.

The company argues, on the other hand, that while these expenses are one time for the test year, there are other similar expenses that will occur in the attrition years which are not considered because of the current ratemaking methodology which only look to the test year. Thus, the company position is that in any one year, there will likely be so-called one-time expense items. Also, SDG&E argues that if the one-time expense is amortized over three years without interest, then it will not be allowed full recovery for a legitimate expense.

We are persuaded by the staff that the most proper treatment is to recognize the expense if reasonable but to spread the expense over the three-year rate case cycle. We realize that this might not allow full recovery of a legitimate expense but we also realize that these projects are in the control of the company and that any delay beyond the estimated completion dates is a windfall for the utility. In these circumstances, it appears reasonable to follow the staff's suggestions. It is also readily apparent that the cause of this issue is the current ratemaking plan of conducting a general rate once every three years.

2. *Franchise Fees on Interdepartmental Sales*

[2] SDG&E pays a fee to do business in various cities in its service territory and a portion of this fee covers the sale of gas. The fee is often based on the amount of sales. In the past, "sales or transfers" of gas from the gas department to the electric department has been excluded from the fee calculation. There is currently in litigation a suit on behalf of several cities against another combined utility (PG&E) to include these interdepartmental sales. In this application, SDG&E has computed its potential liability in the event the cities prevail and requests recovery of this amount plus the forecast franchise fees also.

In this proceeding, both the City of San Diego and the Federal Executive Agencies (FEA) argue strenuously that to allow recovery of the past franchise fees would be prime examples of "retroactive ratemaking". The staff also agrees. Franchise fees of specific dollar amounts were authorized to be recovered in rates. The Commission's determination of reasonable franchise fee expense should not be reviewed now. When the legal issue is resolved, the date from which the fees accrue is established, and the exact dollar amount determined, then the company should bring this matter to the Commission's attention. We will consider SDG&E's request at that time.

3. *Escalation Rates*

Both SDG&E and PSD developed labor and nonlabor escalation rates for 1984, 1985 and test year 1986 based on a methodology keyed to Data Resources Incorporated (DRI) models and forecasts. As indicated by the 1984 general rate increase case decision, the appropriate modeling technique for escalation of nonlabor expenses was very controversial with the Commission staff objecting to SDG&E's DRI analysis due to its size and complexity, its lack of sensitivity to regional or SDG&E specific costs, and staff's liability to verify the results of the model. Our Decision (D.) 83-12-065 favored the greater accuracy inherent in the DRI method, but did not adopt it due to staff's concerns. SDG&E has reduced the size of the model from 120 very detailed price indexes to 69 basic indexes. Moreover, SDG&E has agreed to supply staff with the forecast of the DRI price indexes which drive DRI's Utility Cost Forecasting (DRI-CFS) model to produce the nonlabor factors.

The DRI-CFS model is a generic model designed to capture the effect of inflation on electric and gas utilities. While the underlying model structure is generic, it does, however, rely upon SDG&E's specific accounting data for the final results. The model is based upon 14 major expense categories. Each major expense category is then broken down into an operations and maintenance components. The operations and maintenance components are then further disaggregated into functional subcategories based on the FERC Uniform System of Accounts. At this stage of detail, price indexes representing basic cost elements are coupled with SDG&E accounting data weights to form company specific cost escalation measures. PSD and SDG&E recommended labor and nonlabor escalation rates are adopted as follows:

	Labor	*Nonlabor*
1984	5.5%	3.9%
1985	5.5%	2.9%
1986	3.9%	3.7%

II. *Revenues*

PSD utilized recorded economic, demographic, and customer data through June, 1984 in its econometric models in order to produce estimates of customers, sales and revenues for residential and non-residential customers of SDG&E's electric department, gas department, and steam department for 1986 test year purposes. The minor variations between PSD and SDG&E estimates occur due to use of more recent data by the PSD, and use of different variables and modeling techniques.

Rather than litigating the theoretical differences between the forecasting models of the PSD and company, the parties followed the Commission's instruction from the 1984 general rate case that ". . . because of ERAM and SAM, we will expect the parties in the future, if possible, to come to their stipulations early in the proceeding and thereby save costly hearing time."Our tables herein reflect stipulated 1986 sales and customer estimates for all three departments. No other party contested these estimates and they are adopted.

III. *Customer Accounting and Collection Expenses (Accounts 901-905)*

The company estimates for these expenses were based on the recorded expenses for the year ending June 1984. Besides the base year estimates, the costs for several new programs were added to arrive at a test year total. The new programs and the associated costs (thousands of dollars - 1983) are listed below:

1. Centralized telephone center extended hours - 142

2. Customer service retraining - 235.3

3. Emergency communications - 56.4

4. Credit scoring - 47

5. Bad debt match - 70.6

6. Additional meter deposits - 107.3

7. Field collection fee - 28.2

8. Collection follow up - 769.2

9. Customer masterfile conversion - 329.2

10. Community outreach - 348.1

11. Information systems - 769.8

In addition to these new programs, the company is requesting the transference of funding (about $1.2 million) from now defunct conservation programs (Acct. 908) to the customer accounting area (Acct. 903).

The staff has opposed the implementation of the Bad Debt Match program in addition to the transference of funds from the conservation accounts to this area. The FEA opposes the requested treatment of the Customer Masterfile Conversion, Information System, the Community Outreach Program, as well as the transference of funds. The FEA also contests the stipulated uncollectible factor.

The FEA argues that the expenses associated with the Customer Masterfile Conversion program and the Information System are one-time expenses and should, therefore, be spread over the three-year rate case cycle. The record clearly shows that the expenses are indeed one time extraordinary expenses. In accord with our earlier discussion of extraordinary expenses, we will adopt FEA's recommendation and spread these expenses over three years.

The next FEA recommendation is that the Community Outreach Program be deferred in part. FEA argues that this program provides no savings to ratepayers and that, therefore, this program should be phased-in over two rate cases so that the ratepayers would not be unduly burdened.

We believe that the company has shown that this program offers substantial benefits to its hardship customers who are having difficulties paying their bills. The program envisions one program coordinator and seven account representatives (one for each district). We will adopt the test year expenses for this program.

[3] The PSD supported by the FEA oppose any transfer of funds from conservation programs to the customer accounts expenses. The issue arises because many “high bill inquiries” were previously charged to the RCS program. The RCS program expires in 1985. The company believes that there will remain a need for these services and proposes to now charge these services to the customer service accounts. The basic high bill service call involves a company representative visiting the customer's home and reviewing historical usage, looking for gas and hot water leaks and discussing all factors that can affect usage. The company has currently projected about 8,300 such calls and with the demise of the RCS program now expects a total of 20,000 such calls.

The staff argues that the company has not provided evidence to substantiate the additional 12,000 calls. We agree with the staff that there has not been sufficiently substantial evidence produced to justify the 12,000 additional calls. There has been sufficient notice of the demise of the RCS program to allow any required accounting adjustments. The $1.2 million for both residential and commercial/industrial customer groups will not be transferred to these accounts (901-905); the amount not spent will be returned to ratepayers.

[4] The final *program* issue to be discussed is the “Bad Debt Match” program. This is an automated system to identify customers with outstanding bills when they apply for service whether moving within the service territory or moving from another service territory. The program cost is expected to be about $70,600 and save about $77,000. The savings are forecast to be even greater if other utilities participate in a similar program.

The staff argues that the SDG&E proposal is premature due to lack of utility partners and should be rejected pending a Commission decision authorizing a statewide program for all energy utilities. The staff also notes that SDG&E is already increasing its meter deposits and implementing a credit scoring program designed to identify high risk new customers.

We find that the “Bad Debt Match” program is premature as suggested by the staff. The other programs aimed at mitigating the bad debt problem should be given the opportunity to work before implementing the “Bad Debt Match” for a single utility.

The last issue in the customer accounting costs area is the “uncollectible” rate. The staff and the company have agreed upon a methodology which is a multiple regression model approved in SDG&E's last general rate case. The stipulated rate is .225% which does not include the effects of the bad debt match program. The model includes recorded data only through 1983.

The witness for the FEA demonstrated that there was both a significant increase in the rate in 1985 followed by a significant improvement in the rate in 1984. The FEA, therefore, argues that the model does not reflect the improved 1984 number and, therefore, produces an estimated rate for the test year which is too high. The FEA witness, therefore, takes the difference between the 1984 estimated and recorded as an adjustment to the stipulated rate. The result is .200% on a comparable basis.

The uncollectible rate for the last several years is shown below:

1980	.140
1981	.183
1982	.189
1983	.224
1984	.197 (actual)
1985	.172 (projected)

Although we continue to endorse the model used by both the staff and the company, it appears that the adjustment recommended by FEA is reasonable in light of the later recorded experience.

IV. *Administrative and General Expenses*

This was one of the most hotly contested subjects in the Results of Operations portion of this case. As usual, the controversy was the result of lack of clear guidelines on the estimating techniques endorsed by us and a departure from "business as usual" (five-year trend) on the part of the staff in addition to the fact that this area (A&G) is made up of very many small expense categories.

The major expense categories in this area include: salaries, office supplies and expenses for general officers and administrative employees (Accounts 920 and 921); outside legal, audit and other expenses (Account 923); property and liability insurance (Accounts 924 and 925); pension and benefits (Account 926); franchise fees (Account 927); regulatory commission expenses (Account 928); miscellaneous general expenses, including contributions, dues and donations (Account 930); rents (Account 931); and maintenance of general plant (Account 932).

In our decision in SDG&E's last rate case, we in essence adopted an estimating methodology that relied on recorded expenses that were then adjusted for real growth. The company in this case has followed that method in many areas and presented its estimates accordingly. The staff, on the other hand, is disturbed by a phenomenon that it has described as "base creep." This is a description of what occurs in following year's estimates when a utility spends a larger than expected or authorized amount in any historical year. The increased amount is then included in the base used to estimate future years. This can potentially be even more significant when a utility underspends during a test year but then overspends by a like or greater amount during an attrition year which is then used as the recorded year for estimating a future year and is not part of a trended estimate.

[5] Another aspect of the staff presentation is that it ties the growth of customers and/or sales to allowed real growth. SDG&E has interpreted the staff position to be that A&G expenses will only be allowed to grow at the same rate as customers and sales. We disagree with this interpretation. We look with favor on the staff concern and our view of the staff position is that when A&G expenses are estimated to grow (real growth) at a faster rate than customers and sales then a red flag is raised. In this situation, it then becomes more of a responsibility of the company to explain in detail the causes and results of such excess growth.

A. *Administrative and General Salaries and Expenses (Accounts 920 & 921)*

Executive Salaries and Expenses - 920.1, 921.1

Other Salaries and Expenses - 920.2, 921.2

920.1 and 921.1

[6] The first area in which the different methods surfaces involves the estimate of executive salaries and expenses. The company has estimated 1986 test year salaries and expenses by using the recorded 1983 figure and then adding standard escalation. PSD ironically uses the same method but adjusts the recorded 1983 figure by removing about $250,000. The staff adjustment is the removal of "bonuses" embedded in the 1983 figure. The staff also presented the following table:

TABLETABULAR OR GRAPHIC MATERIAL SET FORTH AT THIS POINT IS NOT DISPLAYABLE

The staff adjustment is predicated on the theory that "bonuses" will only be awarded in years when the company does better than expected. The staff reasons that in those years there will be extra savings out of which the bonuses could be awarded and that, therefore, the bonuses should not be built into the expense structure of a "normal" forecast test year. We agree that the staff adjustment is warranted until such time that the pay structure of the utility is more closely scrutinized.

In addition to the staff adjustment regarding bonuses, we feel that there should be further adjustments in light of the evidence regarding the historical growth shown in the table above. We, therefore, will not authorize any inflation in these two subaccounts (920.1 and 921.1) for the period from 1985 to the test year 1986. Basically, we are saying that we will recognize the base 1983 salary levels and will allow normal inflation for 1984 and 1985, but we expect that the 1985 salaries will not be adjusted for inflation.

920.2, 921.2, and 922

[i] It is this subaccount which encompasses the major staff adjustment for "base creep." The reason for this is that SDG&E has estimated these two subaccounts by utilizing 1983 recorded data to which is added a factor for real growth. This total is then escalated in normal fashion for inflation. For Acct. 920.2, SDG&E projects that it will experience the real growth rate that it has experienced for the period 1982 - 1983 or 2.9%. For Acct. 921.2, the

company expects to hold real growth somewhat below the growth experienced for the period 1979 - 1983. SDG&E requests a growth rate of 5.1%. We will adopt as a cap for these accounts the growth in the number of customers (2.8%).

The staff notes two problems with the company approach. The first is that real growth should not exceed the rate of growth in the number of customers. The second is the so-called “922 effect.” The 922 effect in conjunction with the SDG&E method produces real growth in this account in excess of 7%.

In order to understand the 922 effect, one must realize that a portion of the 920 and 921 accounts will be eventually transferred to rate base (capitalized). As capital projects (construction) decline then the activity in 920 and 921 related to capital projects should also decline. If the years forming the base for the forecast year had more construction activities than the forecast year, then the forecast amounts would be overstated. Account 922 is a credit account that captures the amounts in 920 and 921 to be eventually transferred to rate base. This account is estimated using a percentage ratio. If the forecast ratio is low compared to the ratio of a past period of high construction and if this low ratio is applied to a forecast period with lower construction which used a high construction period as an estimating base then the net difference between 922, on the one hand, and 920 and 921, on the other, will be overstated.

The staff has tried to rectify this problem by removing from Accounts 920 and 921 any growth related to construction. The remainder is growth related to growth in the number of customers.

We believe that the staff has indeed correctly analyzed the 922 effect, but that the staff has not adequately explained its calculations. We see the problem as a mismatch of estimating periods. The mismatch is a past period base with a future year transfer ratio. The solution we will adopt is match the transfer ratio with the base period used to estimate the forecast year. In this instance, the historical transfer ratio was 16%, although the forecast ratio is 10%. We will, therefore, apply a ratio of 16%, to our adopted amounts for 920 and 921 which were based on the historical period to arrive at the adopted estimate for Account 922.

B. *Outside Services Employed* (Account 923)

The company uses a five-year average using 1979-1983 data to estimate this account. The major issue in this account is the recovery of “management audit costs.” Minor points raised by the FEA concerns the outside legal services.

[7] FEA recommends that certain legal fees be disallowed based on the fact that the firm was located in the area of Washington, D.C. There is no adequate basis for the FEA recommendations in this area and they will not be adopted. The more substantive controversy regards the management audit fees.

[8] Decision 90405, dated June 5, 1979, ordered that a management audit of SDG&E be performed. The consulting firm of Ernst and Whinney (EW) was selected by the Commission and commenced its audit in August 1983. A final report was issued in May 1984. There were 166 recommendations. The staff has reviewed the recommendations and included the effects of implementation of many of the recommendations in its individual expense accounts.

In this application, SDG&E seeks recovery in the test year of:

EW costs	=	$ 682,305
In-house costs	=	$ 364,394
Booze Allen and Hamilton costs	=	$ 83,067
		$1,111,766

The staff recommends that the BA&H costs ($83,067) and the in-house costs ($364,394) be disallowed and that the remainder be spread over the three-year rate case cycle. The FEA recommends that the allowed amount be spread over six years.

The first disallowance that we will discuss is the one involving Booze Allen and Hamilton costs. The basis for the controversy is that BA&H was first selected to perform the audit but after completing a portion of the work was asked to resign from the project for reasons discussed below.

The reason that BA&H was asked to resign was that there was an apparent conflict of interest arising out of the fact that BA&H had performed certain executive search activities that resulted in the placement of certain executives at SDG&E during a period that had ended some 12 years earlier.

When the audit was required, the selection of an auditor was to be made by the Commission staff. The staff drew up guidelines regarding conflict of interest that required reporting by the candidates. SDG&E knew of the guidelines and knew of the candidates. It is the staff position that SDG&E failed to inform the staff of a possible conflict before the selection.

The facts appear different than the staff position. First, it is clear that the duty to report was the primary responsibility of the candidates which did not report any such conflicts. Secondly, it appears that the guidelines were not clear concerning the time periods and actions that could comprise a conflict. And thirdly, SDG&E did report regarding BA&H activities concerning work performed by BA&H for SDG&E regarding budgeting and salary matters more recently than the executive search activities. It is clear that the failure to obtain the information relied upon by the staff in disqualifying BA&H prior to its selection was not the fault of SDG&E. The expense associated with this activity ($75,000) will not be disallowed.

The next matter concerns the in-house costs associated with the audit. When the audit commenced, SDG&E set up an in-house management audit section to facilitate the audit process. Personnel were assigned to this section that would normally be assigned to A&G. Costs were incurred by this section during 1982, 1983, and 1984. During the preparation for this case, SDG&E excluded the in-house costs incurred in 1983 from the 1983 recorded figures because it seeks all the costs separately. The staff and FEA argue that those costs should have been recovered in the rates established in SDG&E's 1984 Test Year rate case; they argue in the alternative that the audit unit was organized by a reallocation of company resources and thus the company has already been compensated for the costs incurred. However, the staff has no objection to adding the costs incurred in 1983 back into the base year accounts for the purpose of estimating future expenses.

We disagree with both the staff and SDG&E that the expenses associated with the management audit section incurred in 1983 should be added back to base year expenses for estimating purposes. Our view is either of two situations prevailed. The first is that additional personnel were hired to perform the duties normally performed by the audit section personnel. The other is that the A&G staff was more productive and was able to perform the required duties with fewer personnel. If the first prevailed, then those costs would be reflected in the recorded 1983 expenses; if the second prevailed then the recorded costs for 1983 are a more accurate reflection of the required expenses and, therefore, serve as a better basis for estimating future years.

The remaining dollars are legitimate expenses and recovery will be authorized. We will accept the recommendation of the staff and FEA and not allow recovery in a single year; rather, we will spread recovery over three years as discussed in the section on nonrecurring one-time extraordinary expenses above.

C. *Pensions and Benefits* (Account 926)

[9] As usual, this area has the flavor of real controversy because this is one area whose significance we all can appreciate. The staff has proposed major disallowances in this area. The three main areas of contention are:

1. Pensions

2. Medical costs

3. Employee Savings Plan

These three areas will be discussed in order. The first concerns the costs associated with the pension plan. The major difference between the staff and SDG&E is a result of the different estimates of the number of participants. Staff has assumed a reduction in the workforce of 271 employees which estimate comes from the recommendations of other staff employees. The staff converts this number into a percentage without acknowledging that dependents, in addition to employees are included in the pension plan costs. The difference regarding the number of employees will be resolved in our resolution of the other expense items. When the number of employees participating in the plan is arrived at, the SDG&E methodology computing pension costs should be used.

The next item is medical costs or health costs. Staff has acknowledged that the Company has already implemented most of its recommendations, has the lowest cost per employee of California utilities for health care and its escalation rate is already in the range that staff has proposed. Secondly, staff's calculations are again improperly made on the basis of employees rather than participants, despite the acknowledgement that plan participants include more than simply employees. This approach, therefore, understates the Company's actual costs. We find that SDG&E's test year expenses are reasonable and that they will be authorized.

[10] The final item in contention is the employee savings plan which is the third most costly benefit program at SDG&E representing about $3 million or 9.5% of the total employee benefits package. The cost of this program has doubled over the past three years, due primarily to increased tax advantages occurring from Section 401K of the IRS code which converts this payroll deduction from an after-tax to a pre-tax deduction. This has vastly increased the popularity of this type of benefit and led to increased enrollment and increased employee contribution up to the maximum allowed percentage of annual salary. The company matches 50% of employee contributions up to 6% of annual salary. The employees may continue to contribute an additional 5% of salary up to an overall maximum of 11% of annual salary. The additional 5% continues to receive the Federal tax advantage but is not matched by company funds. PSD recommends that the cost of the savings plan be borne by the stockholders.

The company argues that its wage and benefit package is one of the lowest of the California utilities and that any reduction in this area should be matched with a corresponding increase in some other item of the total compensation package.

We agree with the company that an immediate complete disallowance of this item is unwarranted by the staff showing. On the other hand, the “employee savings plan” appears to be an open ended offer on the company's part and as such is beyond the control of the company and also beyond our scrutiny. We will, therefore, cap the dollar amount of the company contribution at the 1985 level and not inflate this for 1986. It is our expectation that the company contribution portion of this plan will either decline or be picked up by the shareholders. By not making the disallowance at this time as recommended by the staff, we are allowing the company the opportunity to negotiate this benefit into a more acceptable item of the employee pay package.

The last minor item in this account concerns the company's contributions to various organizations. The FEA recommends disallowance of $120,000 because there is no ratepayer benefit associated with these contributions. The staff and the company have arrived at a stipulated level for these expenses that can be considered normal expenses of any on-going enterprise. The stipulated level will be authorized.

D. *Franchise Fees* (Account 927)

This account has been discussed and all issues resolved earlier.

E. *Regulatory Expenses* (Account 928)

[11] The FEA recommends the disallowance of certain regulatory expenses because the company has estimated its expenses using a five-year average. The FEA points out that SDG&E has neglected to allow for the increased period (three years) before the next general rate case. The FEA recommends a disallowance of $241,000 but fails to show how the amount was developed. We feel that the nature of regulatory work has increased in its complexity more than enough to offset the longer rate case cycle. The stipulated amount will be adopted.

F. *Miscellaneous General Expenses*

The next account for discussion contains several items of difference between the company and other parties. The major categories are:

1. Bank Service Fees

2. EEI and AGA Dues

3. Research, Design, and Development

1. *Bank Service Fees*

[12] The first to be considered is bank fees. This item is inextricably tied to the certain aspects of working cash.

The basic concept is that banks charge fees for services to its customers, one of which is SDG&E. These fees can be paid in one of two ways. The first is that the fee could be paid directly. The second is that when the customer (SDG&E) maintains amounts in its accounts which earns interest, then the interest can offset the fees.

The amount that the banks must keep in the accounts is a rate base item (working cash). The fees paid directly are expensed as an A&G item. The issue contested by the staff is what is the least expensive way of paying these fees. The staff suggests that more of the fees should be expensed and less capitalized as compared to the company estimate. The staff estimate holds the amount capitalized in 1983 constant and increases the expensed portion to make up the difference.

All parties seem to agree that the less expensive way to pay for these costs is to expense as much as possible. The issue gets wound into the rate base issue because the company must maintain certain minimum bank balances to provide overdraft protection. Overdraft fees are much more expensive than regular fees and it is generally agreed that minimum bank balances must be maintained. Since these balances must be maintained, the interest which they accumulate offsets a portion of the bank fees. Therefore, there are two real issues surrounding this issue. The first is what is the amount of the minimum bank balances to be maintained for overdraft protection. The second is the amount of the bank fees for the test year.

The staff assumes without any basis that the minimum bank balances will remain constant at the 1983 level of $2.0 million. The company, on the other hand, estimates $3.0 million. This estimate is based on a hindsight review of its operations in 1984. The company managed to keep its minimum bank balances to $2.3 million in 1984. A company cash management team reviewed its results and determined that the $2.3 million was a minimum cash balance. Admittedly, this is not the most objective review, however, it does have a degree of credibility.

The next question is what is a reasonable estimate of the test year minimum balances necessary to provide overdraft protection. We believe that the company should be able to manage with $2.8 million which should capture both growth and inflation from the 1984 figure.

The final part of the equation is what portions of the bank fees will be offset by the interest earned on the $2.8 million. The company witness testified that these fees have been increasing at the rate of about 20-25% a year for the past two to three years and that they expect that this rate of increase will continue. The staff does not take exception. We believe that the period of readjustment following banking deregulation is coming to an end. Therefore, we will allow $670,500 as the estimate of bank fees for the test year. The $2.8 million will provide an offset of $239,000 the amount to be expensed is, therefore, $431,000.

2. *EEI and AGA Dues*

[13] This expense item has caused a great amount of tribulation over the years. The main issue has generally been to determine whether or not the ratepayers have received sufficient benefits to warrant the ratepayers paying for all or at least some portion of the fees. Although we have been very inconsistent in our treatment of the different utilities on this issue, it does appear that this issue should be treated in an almost generic fashion. That is why should the ratepayers of SDG&E pay a different portion of these fees than the ratepayers of PG&E or SoCal Gas.

Regarding SDG&E, we have previously disallowed the entire amount of the fees and stated that we would continue this disallowance until such time that SDG&E made an adequate showing of ratepayer benefit. Since we made those statements, we have considered this same issue in the rate cases of two other major utilities (SoCal and SCE). In SCE's case, we allowed 75% recovery and in SoCal, we allowed 99% recovery (all but lobbying). In this case, SDG&E has made a showing that is about as substantial as that made in the SCE and SoCal cases.

The staff argues that the company still has not presented adequate evidence to allocate the benefits of membership between the ratepayers and the shareholders and, therefore, no membership fees should be authorized. The staff's secondary recommendation is that about 50% of the fees should be disallowed.

The most unique argument that we have seen on this issue was presented by UCAN. The heart of the UCAN argument is that there can be no method to allocate the ratepayer vs. shareholder benefits/detriments. It is, therefore, the result that some *portion* of any dues contributed by ratepayers will be used for purposes not in the ratepayers' benefit.

Another fact that has a bearing on this issue is that NARUC is apparently studying this issue and will be preparing ratemaking recommendations for this expense in the near future.

We believe that consistency for the utilities in the treatment of these expenses is required, especially when they make substantially similar showings. We will allow SDG&E to recover 75% of the EEI dues and 99% of the non-advertising portion of the AGA dues.

3. *Research, Design, and Development*

In this application, SDG&E has included in its A&G expenses an estimate for its 1986 test year RD&D budget. The test year estimate includes approximately $6 million for the Heber project. Although the Heber expenses are included in this case, SDG&E has also filed an Advice Letter seeking the same recovery. On November 6, the Commission granted a portion of the company's request to revise electric authorized base rate revenue to offset SDG&E's portion of the 1985 projected expenditures for the Heber project. (Resolution E-2055) With this decision, the remaining request is $5.174 million. The staff is recommending $4.190 million, a difference of $984,000.

Any discussion of RD&D must take into consideration D.82-12-005 which set forth our major requirements for RD&D with an approved method of assigning priorities the various projects. In our decisions, in both SoCal and SCE 1985 test year rate cases, we elaborated on those guidelines. The company testimony sets forth how it relied upon and considered our guidelines as set forth in those decisions. The staff does not allege any major deficiencies in SDG&E's methods. The staff, rather, reviewed the projects and made many small adjustments based on its on subjective judgment.

[14] We will approve the bulk of SDG&E's proposed RD&D budget, apart from the Heber project. We are in close agreement in particular with the upper half of the company's priority list, which indicates that SDG&E's selection and evaluation process is basically sound. Staff has made some suggested adjustments to the proposed budget, and to indicate our general judgment about the appropriate direction for RD&D for a utility in SDG&E's current circumstances, we will discuss some of the proposed programs specifically.

In addition to the guidelines of D.82-12-005, our evaluation is influenced by SDG&E's announced intention not to rely on large central generation plants, the absence of such central plants from the company's resource plan for the mid-term, and the high level of SDG&E's rates, which compels overall belt-tightening and closer attention to cost-effectiveness.

Accordingly, we approve all of SDG&E's requested budget for involvement in industry organizations, except for some of the travel adjustments proposed by staff. We believe that participation in these industry groups will allow SDG&E to satisfy many of its research needs at a relatively low cost.

Staff pointed out that about $300,000 of the proposed budget was for travel. We share staff's perception that this amount is excessive. We will adopt most of staff's adjustments, primarily to emphasize to the company that all RD&D expenditures should be closely scrutinized by the company to derive the maximum benefit. We adopt $20,000 of staff's $40,000 adjustment to EPRI-Company Participation, and its recommended travel adjustments to SDSU Power Engineering Research, Dispersed Storage and Generation, RD&D Test Facility, and WEST Associates-Company RD&D Participation.

Staff recommends authorizing only $56,000 of the $156,000 requested for the Therma1 Energy Storage project. The request covers the last three years of a nine-year project that has been fruitful and has particular potential benefits for SDG&E. We will authorize the company's request.

Staff reduces the authorization for Kapiloff Acid Deposition Research to $115,000 for 1986, based on 1983 experience and the likelihood that plant closures and retirements will reduce the emissions which are the basis for the assessment by the Air Resources Board. We agree with staff.

Staff recommends deletion of the Utility Industry Advanced Generation Technology Participation, Modular High Temperature Gas-Cooled Reactor, Solar Thermal Research Assessment, Advance Coal Research, and Solar Cooling Evaluation projects. Among other reasons, staff argues that monitoring, rather than direct participation, is the best way for SDG&E to keep abreast of developments in these areas. Staff accordingly increases the budget for RD&D Administration and Coordination by $20,000 to allow for monitoring. We agree with these adjustments. We also note that although staff recommends a reduction from the utility's request for Evaluation of Renewable Resources to $115,000, this still represents a large increase from expenditures in past years. We will approve this program at the level recommended by staff, but we will also delete the Wind Resource Assessment program, which seems to perform services for third parties at ratepayers' expense, and will limit the budget for the Wind Park Monitoring to $8,000, because we believe that the desired information is already available from other California utilities. Although we have related concerns about the Solar Insolation Data Collection program, we will authorize the staff's recommended budget because of the particular potential for benefits to SDG&E.

We accept the staff's adjustments to Research, Experimentation, Development and Demonstration Non-Generation Opportunities Evaluation (R,E,D&D) and the recommended budget ($36,000) set forth in staff's brief for the Pala Passive Solar Homes, for the reasons stated by the staff.

We find the description of the proposed program for the UCSD Energy Center to be extreme1y vague, but in light of the utility's statement that the Center "has been an invaluable resource for SDG&E for many years" (Exh. 47, p.8-27), we will authorize $22,000, the amount of expected expenditures for 1985.

Finally, we will delete the Energy Management Cooperative project, because we believe similar work has been performed by other utilities and because of the low priority assigned to the program by SDG&E. Programs with a lower priority than SDG&E's 100% of budget level will also not be authorized.

With these adjustments, our adopted budget for RD&D for 1986 is $4,242,000 in 1983 dollars. We believe that this amount will permit an adequate level of RD&D for SDG&E. We note that this represents a slight increase in non-Heber RD&D from the 1984 recorded expenditures. Again, we wish to point out that we have discussed some of the projects in detail not to bind management to a specific budget, but to give some indication of what we believe is an appropriate direction for SDG&E's research to take at this time.

[ii] One final comment is appropriate. The results of several of the programs might be useful to unregulated affiliates of SDG&E under its proposed plan for diversification. In particular, the Fuel Cell Demonstration proposal includes explicit provisions for marketing, and the R,E,D&D Non-Generation Opportunity Evaluation and renewable resources projects could benefit an affiliate. We have not yet ruled on the diversification proposal, but we are very concerned about the possibility that these unregulated affiliates might profit from projects paid for entirely by ratepayers, a concern raised by both staff and UCAN. If this problem develops, SDG&E should be aware that, at a minimum, we will closely scrutinize any such affiliate to ensure that ratepayers recover a fair value for the results of research that they have sponsored. Other remedies may also be appropriate, but those will be developed in the context of the diversification case.

G. *Maintenance* (Account 932)

The next item to be discussed in the A&G area is Account 932. For this account, SDG&E based its estimate on 1983 recorded expenses which it then escalated to arrive at a test year estimate. The staff, on the other hand, excluded approximately $545,000 from the base year and then performed the escalation. The result is a difference of $408,000.

The staff made its adjustment based on the fact that in its judgment the $545,000 in 1983 was a one-time nonrecurring expense. The item covered by the expense was a major renovation/maintenance project at a fleet maintenance, gas operations and record center facility (Station A).

The company argues that it cannot be shown that these types of expenses will not be required at other facilities and that the historical amounts in this account indicate that similar work has been performed at other facilities. We note that the expense level in this account jumped about 30% from 1982 to 1983. We believe that the staff adjustment is reasonable and, therefore, adopt it.

H. *Cogeneration Expenses*

[15] The staff has analyzed the performance of SDG&E in making purchases from QF's and finds that the company has performed satisfactorily in 1983 and 1984.

In this application, SDG&E requires funding about twice what it was authorized in the 1984 rate case ($1,150,200 vs. $616,000). The company argues that this is a zero based budget which recognizes that SDG&E has consistently overspent in this area. Also, the EW Management Report recommends certain additional activities in this area. The staff estimate is designed to maintain the program at its present level. The major dollar difference has to do with the number of personnel associated with the program. The staff recommends 12, and the company 20 positions. We will authorize some growth in this program above that recommended by the staff. We believe that an amount about 25% greater than recommended by staff is necessary to implement the EW recommendations and maintain the program on an adequate level. The authorized amount is $1,062,500.

V. *Production Expenses* (Accounts 500-557)

SDG&E has divided these expenses into three categories:

1. Steam power plants

2. Nuclear plants

3. Other related power production related expenses.

These expenses provide for the day-to-day operation of the plants, including all maintenance and projects designed to increase efficiency and reliability.

Numerous stipulations have been reached between the company and the staff resulting in a reduction of the requested amount for this item from $95,835,000 to $89,583,000. The remaining issues have been narrowed and are discussed below. Rather than focusing the discussion on particular accounts, we will instead consider the differences in terms of programs in the same manner as the parties. The program areas are:

1. Technical Services ($53,300 difference)

2. Power Plant Projects ($939,000 difference)

3. Overhaul Expenses ($516,000 difference)

4. Fuel Handling Expenses ($848,900 difference)

The circumstance that makes this area so difficult to resolve is the dramatically changing resource mix of the company. The staff points out that traditional generation is going down while production expenses are going up. For the test year, for instance, conventional steam generation is about 57% less than the recorded generation for the 1979-1983 period. Offsetting this trend are certain other factors such as increased cycling of the plants, increasing age of the plants, and the fact that many expenses vary not according to production but according to installed capacity.

A. *Nuclear Expenses*

All issues relating to this area have the subject of a stipulation and an ALJ ruling. The 1986 and 1987 Operation and Maintenance (O&M) and Administrative and General (A&G) expenses for SONGS 1, 2, and 3 and Common are based upon the stipulation between SCE, SDG&E, and the staff which was adopted in Edison's General Rate Case D.84-12-068.

B. *Technical Services*

The technical services department provides technical assistance to power plants. This assistance includes: annual Air Pollution Control District (APCD) testing, air quality analysis at the power plants, water analysis, chemical analysis, metallurgical analysis, and various in-house services. The staff has used a five-year average estimating methodology (1979-1983) while the company has used a four-year average (1981-1984). We find that the company's four-year average reflecting increased technical services in 1981 is more accurate for these services which vary more by installed capacity than production. The company estimate will be adopted.

C. *Power Plant Projects*

During the test year, there are five power plant projects at issue: a control room simulator, certain condenser tube replacements, and three dredging projects. The staff takes no issue with the need for these projects. The difference between the company and the staff is that SDG&E seeks one-year recovery whereas the staff recommends spreading the costs over the three-year cycle. Our discussion of this problem in the A&G area is equally applicable here. These projects appear to be one-time nonrecurring projects. The staff estimate will be adopted.

D. *Overhaul Expenses*

The issue on overhaul expenses is identical to the issue in Power Plant projects above. Our resolution is also the same. The staff estimate is adopted.

E. *Fuel Handling Expenses*

[16] The last major issue concerns fuel handling expenses. Here the company requests $948,900 and the staff recommends $100,000. The company used a production cost model and a fuel handling model. The staff estimate is

based solely on judgment without any basis for the $100,000 estimate. In these circumstances, we are left with either the company estimate or else our own estimate based on our judgment and the facts on record.

The main staff criticism is that the company's estimating method produces a figure that is insensitive to amount of fuel oil deliveries. For instance, the staff notes that SDG&E's oil burn for 1984 was about 1.8 million barrels (bbls) with a fuel handling expense of $940,000. The projected oil burn for 1986 is about half (878,000 bbls) of the 1984 burn with the fuel handling expenses to be slightly higher. Staff laments this fact but did no investigation of the underlying factors to determine the reasonableness of this estimate although it did make an estimate for a fixed expense related to barging operations.

The company provided no evidence to show the reasonableness of its estimate other than to show that its model had predicted 1984 expenses accurately. SDG&E did provide testimony to show that its barge operations were reasonable. It is implicit in the company's position that virtually all fuel handling costs are fixed rather than variable. However, the company does not show what these expenses are and why they are fixed except for the long-term lease of the barge which is necessary for fuel oil deliveries to the South Bay facility.

The company apparently takes its burden of coming forward with the evidence and substantiating its request to the Commission very lightly. Without any quantification of the fuel handling expenses, we must try to convince ourselves that SDG&E's counterintuitive position is factually correct. We prefer to draw our own reasonable inferences.

We find, at this time, that the fixed expenses for the barge are reasonable ($250,000 annually). We also find that at least some portion of the remaining expenses must be variable. We believe that one half of the remaining expenses either do or should vary with the amount of the oil burn. We will use as our base the 1984 fuel handling expenses ($940,000) and from this remove the annual barge expense of $250,000. We will then take one half of the remainder to vary with the fuel burn. Since the 1986 burn is about half the 1984 burn, we will recognize half of the variable expenses. This produces a total estimate for test year fuel handling expenses of $767,500, which we will adopt as reasonable. At the same time, we put the company on notice that a more substantial showing on this point in the next general rate case is required for any such expenses to be authorized.

VI. *Transmission*

[17] There is a difference between the staff and the company of $636,800. (SDG&E - $15,296,700 vs. staff - $14,659,700). About $152,000 of the difference is related to the basic methodology. The staff used a nonnormalized average whereas the company normalized its numbers. The company method is correct. Discussion of other recorded staff adjustments follows.

The staff recommends that $97,800 be disallowed. The company is requesting this amount in Account 570 in order to enhance substation maintenance to the pre-1983 levels. The staff bases its recommendation on the facts that the Ernst and Whinney report commended SDG&E on its substation maintenance activities and that there appears to be no maintenance backlog. We will adopt the staff adjustment.

The next area at issue is “maintenance of overhead lines”. The particular item difference is that the staff is recommending the disallowance of an additional work crew requested by SDG&E ($270,500). The company relies upon its changing nature (increased reliance on purchased power) to justify the increased maintenance effort. We note that the company's request is about a 51% increase in expenses in this account over 1984 and that the staff's figure is about a 40% increase over 1984. We will adopt the staff recommendation.

The last account to be discussed in this area is Account 565 which covers the costs of “transmission by others.” There are more issues here than initially raised by the staff or the company. The first issue contested by the parties is the proper estimate of the expenses related to the Pacific-Intertie. SDG&E used a historical three-year average of increase (6.95%) in this account to apply to the base 1983 levels. The staff used an escalation rate closer to the nonlabor escalation rate stipulated to in this case. The 1984 increase in this account was 16%. We favor the method used by SDG&E as being more closely related to the actual expense item.

[18] Another issue not contested by the staff but raised by SDG&E in its brief concerned the ratemaking treatment of fixed wheeling expenses. In SDG&E's 1982 general rate case, we allowed SDG&E to place fixed wheeling expenses incurred after the submission of the case into a deferred account to be recovered in the following general rate case. This procedure was continued in the 1984 gen-

eral rate case. In this case, SDG&E's estimate includes the cost of such a contract that is not yet signed ($0.8 million) as well as $1.0 million for a three-year amortization of the deferred account. In addition, we are faced with the issue of whether or not this practice should be continued.

SDG&E provides testimony that indicates that this practice works to the ratepayers benefit by encouraging the company to enter into contracts with fixed charges at lower prices compared to interruptible short-term contracts at higher prices. On the other hand, if this practice is to become a standard practice, it seems that both variable and fixed wheeling costs belong in the ECAC procedure. We will discontinue the practice of allowing a deferred account for the fixed wheeling costs in general rate case proceedings. We realize there is merit to the SDG&E position since a three-year rate case cycle makes forecasting such expenses difficult. We will, therefore, allow SDG&E to bring this issue to our attention in a future ECAC proceeding where a more thorough record can be developed on this point.

VII. *Distribution Expenses*

[19] There is a significant difference between the company and staff estimate for this expense. The company estimate of $39,307,000 ($83) is 18.7% higher that the staff's estimate. A very large portion (93%) of the difference is contained in three issue areas:

1. Estimating Methodology,

2. DFIS Project Cost, and

3. Overhead Preventative Maintenance Program.

In our view, the most critical of these items is the DFIS Project which is an automated data base management system capable of automatic map drawing and other property management functions. The project was first begun with a joint feasibility study with IBM. In 1980, the technical feasibility of the project was demonstrated. In 1981, SDG&E decided to delay the project until its cost-effectiveness was proven. After a Total Requirements Statement was prepared in 1983, an economic study was prepared in April of 1984. That study found that the break-even point on a net present value basis was 9.5 years which has now been extended to 12 years with added costs. The system is currently being implemented on a district-by-district basis with completion projected in 1988.

The staff position is that the company should only be allowed the expenses that it projected in the 1984 cost-effectiveness study. The staff has no basis for this recommendation other than the fact that this project is costing more than anticipated. We will allow the requested amount subject to refund. We also share the concerns of the staff regarding cost increases and will direct that SDG&E hire an independent consultant chosen jointly with our staff to provide a report to us before the end of 1986. The report should be the basis of a prudency review of the expenses associated with the entire DFIS project with potential adjustments to rates in the next appropriate rate case.

For the remaining portion of the difference in Account 588, we will adopt the staff's estimate which used 1983 as a base and backed out DFIS and other nonrecurring expenses. The company used 1982 as a base and then added a factor for growth.

The next major area of difference lies in Account 593 which contains the Preventative Maintenance Program for overhead lines. SDG&E added $4.58 million to its base estimates to complete its program of correcting all of the most serious infractions (Class A) in 1986 and beginning the corrections of the less serious violations (Class C). At the level of funding recommended by the staff ($2.29 million) the Class A violation could be corrected in 1986 but the Class C violations could extend to 1993. We will adopt the staff recommended level on the basis that the Class A violations must be attended to immediately and that the next general rate case will provide an opportunity to review the status of the Class C corrections. The company's estimate for the remaining portion of this account relates to tree trimming expenses and will be adopted. The company bases its estimate on a 18-month tree trimming cycle which it has shown to be reasonable.

The remaining estimating issues will be resolved in favor of the staff except for Account 583 in which the staff used nonnormalized historical numbers and for substation maintenance which the staff based its estimate on a per customer average. Other than this problem, the staff method which basically used separate labor and nonlabor escalation rates over a five-year period appears more reasonable than the company estimate which used a combined escalation rate.

There remain a few minor issues. Staff projected a savings due to a management audit recommendation which cannot be implemented until 1988. Therefore, only one-third of the savings will be recognized. Similarly, there was a management audit recommendation with a cost of $30,000 that cannot be implemented until 1989. This cost will not be recognized likewise.

VIII. *Rate Base*

This subject area provided several disputed issues. We will group the issues in the following manner:

1. Electric Plant

2. Gas Plant

3. Nuclear Plant

4. Common Rate Base Items.

A. *Electric Plant*

[20] The first major issue under this heading will be the ratemaking treatment to be afforded to "stored plants" This issue is raised because after the commercial operation of SONGS 2 in 1983, Station B was decommissioned and the four Silvergate units were put in storage. In 1984, after SONGS 3 and SWPL came on line, SDG&E performed a study that showed that during the period 1985 - 1988 energy cost savings could be realized by placing Encina 1 and South Bay 3 into storage.

SDG&E included in its plant estimates the undepreciated amounts for these plants. The effect is that SDG&E will recover the full investment and earn a return on this investment during the period when these plants are not operating. SDG&E focuses its main arguments on Encina 1 and South Bay which will be the last plants "stored" and the first plants planned to be returned to service. The SDG&E argument has two prongs: 1. that the *two* plants remain useful, and 2. that standard accounting practice require the requested treatment for all plants.

The first SDG&E position is that Encina 1 and South Bay 3 can be put back in service if needed relatively quickly (two to three months) and that the storage is only temporary. Further, the plants are providing a useful service in bargaining for economy energy in that no purchased energy should be priced higher than the energy that could be generated if these plants were brought back into service. The accounting argument apparently applies to all the plants. The argument is that our "standard accounting practice" requires that a return be earned on all undepreciated assets and that with group life depreciation, some assets will be retired early and some beyond their assigned useful lives.

The staff recommendation is that the nonoperating plants be removed from rate base but that the plants be allowed to accumulate AFUDC. The AFUDC would be added to rate base when the plants are restored to a productive state. The staff position is based on the premise that it is inappropriate for SDG&E's ratepayers to bear the full capital and operating costs of the SONGS units and SWPL, and to also carry the rate base costs of fossil generating units that are of no use due to the company's excess system capacity and the relative inefficiency of the stored units. The staff counters the accounting argument by emphasizing that the standard accounting rules provide for recovery of the original cost of an investment over its *useful life*. The staff also points out that the standard practice allows for unit depreciation as well as group life depreciation.

We will adopt the company's suggestion for South Bay 3. We find that it is the last to be stored, assume that it is, therefore, the most economical of the stored plants, and because of the uncertain reliability inherent in SDG&E's resource plan we will allow SDG&E to treat it as plant held for future use. Moreover, South Bay 3 is useful as a "yardstick" in bargaining for firm purchased power. We will, however, require SDG&E to justify keeping South Bay 3 in as plant held for future use (PHFU) in their next rate case; this showing should provide analysis of the cost-effectiveness of its inclusion in PHFU.

With regard to Encina 1 and the other units, we will adopt the basic position of the staff that these should be removed from rate base. We will not, however, adopt the staff recommendation for AFUDC treatment. Rather, we find that it is conjecture to estimate when or even if these plants will be reactivated and we will, therefore, treat these plants as retired until they are brought back on line. It is apparent that either these plants are not useful or that some portions of SONGS or SWPL should not be retained in rate base. We believe that both ratepayers and shareholders benefit by retaining the newer more efficient plants in rate base and excluding the older fossil fuel plants.

The specific ratemaking treatment for these plants will essentially follow the suggestion of UCAN. The UCAN position is that the undepreciated balance of the prematurely retired plants be amortized over five years with no return earned. The FEA recommended a longer period - nine years or three rate cases. We find that the UCAN has shown that the two rate case periods or about five years provides an appropriate sharing of the burden between the ratepayers and shareholders. If the plants are brought back on line, the unrecovered balance will be added back to the rate case during either an attrition proceeding or a future rate case.

Rate Base Additions

The staff has contested the in-service date of certain plant additions. The first is the Encina 5 gas conversion project which the company originally estimated to be in service in August of 1986 but now projects a date in February of 1986. The staff estimated a completion date of December of 1986 but has now been provided with a contract for this project. We believe that this project is well under way and will adopt the August 1986 as the completion date.

For Production, Transmission, and Distribution, there was a disagreement on methodology. We find that the proper computation should be based on a ratio of budgeted expenditures to recorded expenditures as later suggested by the company which produces a lower than original estimate.

There was also disagreement regarding the delay of several distribution plant additions. The staff reviewed the status of the projects several months after the application was filed, found that several projects were likely to be delayed, and made adjustments accordingly. The company argues that this is unfair in that while certain projects will be delayed, it is precluded by the rate case processing plan from adding or accelerating projects after the application. We find that the staff's more recent information is controlling and will adopt the staff's adjustments.

SDG&E requests authority to install capacitors on the SWPL in order to upgrade its carrying capacity and thereby increase the company's share of the line from 534 MW to 762 MW by the end of 1986. There are three related issues that condition our treatment of the SWPL capacitor upgrade request. The first is whether the capacitor upgrade is needed. Second, is the addition of capacitors cost-effective. And third, will SDG&E's resource planners ensure that the SWPL and the capacitor upgrade provide cost-effective service and ratepayer benefits over the near and long term.

With regard to the need for more SWPL capacity, SDG&E argues that if the firm capacity it has contracted for is available, the capacity upgrade is justified. SDG&E also states that the upgraded line will provide the opportunity to import economy energy from the southwest in the long term.

With respect to cost-effectiveness, neither the staff nor SDG&E discussed this issue, nor did they directly address the issue of the “purported savings from SWPL,” as was required by Commission Decision 84-12-065 (mimeo. p. 12). Public Staff argues that the SWPL upgrade is not justified for the addition of firm capacity and that under any economic analysis the capacity addition makes no sense. Staff concludes that even with optimistic assumptions the SWPL upgrade is an uneconomic addition. UCAN went further to show through a detailed analysis that the SWPL project with the capacitor upgrade was not cost-effective when compared to very generous avoided cost calculations. UCAN provided the only testimony that succinctly sets forth the utility's cost of purchased power and contrasts that cost with the value of that power to ratepayers.

[21] One of the reasons given for the capacitor upgrade request is that SDG&E has contracted to purchase firm energy through the year 1988 in amounts in excess of the company's share of line capacity. The upgrade would allow the utility to accept and to charge ratepayers for that incremental energy. We are concerned that resources such as the SWPL project are cost-effective to ratepayers. From the evidence introduced in this case, it appears that the SWPL purchased power cost *alone*, excluding the cost of the line, exceeds SDG&E's avoided cost for energy and capacity during the years 1986 and 1987. Moreover, we have no assurance that SDG&E will not sign up expensive firm power contracts that exceed avoided cost in 1988 and beyond. This means that the unconditional approval of the SWPL upgrade would allow SDG&E to accept even greater delivery of purchased power at uneconomic prices.

According to staff and UCAN, the upgrade and SWPL itself could be made cost-effective if more economy energy were purchased over the line. SDG&E appears unable to purchase significant additional economy energy in the 1986-88 period because it has filled the line through firm purchase contracts. Thus, in the near term SDG&E appears unable to make the SWPL project cost-effective with or without the capacitor upgrade.

The third related issue is SDG&E's resource planning and the management of power purchases over the SWPL.

Public Staff concurs with the Ernst & Whinney conclusion that SDG&E lacks the analysis needed to optimize their resource planning so that resource additions are more cost-effective and system efficiency is increased. The SWPL project and the capacitor upgrade present examples of this lack of analysis. The Commission's concern about SDG&E's approach to these matters is set forth in detail in the section on Resource Planning.

With respect to the use of SWPL and the capacitor upgrade, the Commission is concerned about SDG&E's management of power purchases over the line in the long term. Specifically, we want to ensure that SWPL and the capacitor upgrade provide long-term value and cost-effective service to SDG&E customers. To ensure cost-effectiveness and ratepayer benefits, SDG&E must lower their overall cost for power purchased over the SWPL. This can be accomplished if SDG&E purchases significant amounts of economy energy over the line. We want to ensure that this is likely to occur.

Need for the line and cost-effectiveness are central considerations to our determination of whether the capacitor upgrade should be included in rate base. In this case we find the capacitor upgrade to be unnecessary and not cost-effective, unless assurances are made to guarantee the cost-effectiveness of power purchases over SWPL.

In this decision the section on SWPL defines an incentive mechanism to ensure that future power purchases over the line are cost-effective. This will also ensure that the capacitor upgrade is made cost-effective in the near and long term.

Because the cost-effectiveness of the capacitor upgrade is directly linked to SDG&E's management of power purchased over the SWPL, the Commission is obligated to provide a special balancing account mechanism in the ECAC/AER proceeding in order to provide adequate ratepayer protections. This SWPL balancing account mechanism provides both ratepayer protection to ensure cost-effectiveness and a substantial incentive to reduce power purchase costs over the line for the near and long term. We will thus conditionally grant SDG&E's request to put the series capacitors in rate base, since this will allow SDG&E to obtain additional economy energy and to make the SWPL project cost-effective for the present and the future. SDG&E must nevertheless seek the lowest cost purchased power available, which in this case means that transmission capability sufficient to obtain substantial amounts of economy energy is necessary.

B. *Gas Plant*

[22] The first gas plant issue is the ratemaking treatment of the retired LNG facilities. The LNG facilities are located at Chula Vista ($15,100,000), Borrego Springs ($114,000) and Pendleton Marine Base ($175,000). SDG&E initially wanted to “store” these facilities but later changed its position and decided to retire these plants.

The position of the parties was previously discussed in the section on the “stored” electric plants and will not be repeated here. Our resolution is also the same; the undepreciated portion of these plants will be removed from rate base and amortized over five years with no return in the interim.

The next issue also relates to a previously discussed electric plant, the Encina 5 gasification project. The staff suggested that the completion date be the same as the electric plant, although the company projected a July date. We agree with the staff. We have projected a date for the electric plant to be August 1986 and will adopt the same date for the gas plant addition.

C. *Nuclear Plant*

During the proceedings, the ALJ granted a motion to defer all nuclear rate base items to the on going prudency review proceedings. We affirm that ruling. SDG&E, however, raises one additional point regarding this ruling. The point raised by the company is that nuclear related working cash has not been addressed in the prudency proceedings. The company, therefore, requests adoption of its estimate in this proceeding. The staff, on the other hand, assumes that the issue has been deferred in conformance with the ALJ's ruling on its motion. We concur with the staff position. Inclusion of the nuclear related working cash would have the effect of lowering the rate base in this proceeding but to do so would also provide a distorted picture of the true costs of the nuclear power plants when the prudency review proceedings are eventually decided.

D. *Common Plant*

Many of the common plant addition issues were modified in the later stages of the proceeding. Certain initially contested issues were resolved as follows:

1. The Beach Cities project will be included as of July

1986.

2. The company's estimate of the effect of the streetlight sale to the City of San Diego will be adopted.

3. The staff's estimate for 1986 common additions and retirements will be adopted.

The next common plant issue is the staff recommendation that the cost of six properties on the electric side ($555,769) and the cost of one gas property ($44,753) be transferred from Account 105 (Plant Held for Future Use) to Account 121 (Nonutility Property). The basis of the staff recommendation is that the properties either carry no specific definite plan for use or that have resided in the account for more than ten years.

SDG&E argues that the FERC accounting guidelines do not require a specific definite plan and there are no stated time limits on the length of time that plant can be held in Account 105.

In the last SDG&E general rate case decision, we admonished the staff "to take a very close look at PHFU."(D.83-12-065) We further observed that "property that appears to have no use in the company plans for the future or which appears to be speculative in nature . . . should be excluded from rate base."

Staff has taken steps to follow through on our admonition, and we believe that they have done a thorough and responsible job of reviewing the PHFU accounts. SDG&E's argument that FERC accounting rules contain no requirement that the utility have a definite plan of use for the items in PHFU is misdirected, since we are not bound by FERC accounting conventions and since we have repeatedly stated that we expect such a plan for the PHFU of California utilities. In addition to the statement quoted above, we acted in D.83-12-068 to remove several assets from the PHFU accounts of Pacific Gas and Electric Company precisely because PG&E could not demonstrate that it had a "specific and definite plan" for their use.

[23] In this case, we will adopt the staff's recommended adjustments for some of the PHFU items because there is no definite plan for the use of these items and because some of the items have been in PHFU and in rate base since the late 1960s. While we do not specifically adopt the 10-year criterion proposed by staff at this time, we again affirm that utilities should have a definite plan to use assets placed in PHFU within a reasonable period of time.

SDG&E currently has plans to place the Laurel, Carmel Valley, and San Diequito Substations in service by 1995. Since there is a plan for use of these properties, we will reduce the staff's proposed adjustment of $600,522 by $362,414. We note with some concern that the San Diequito Substation will have been in the PHFU account and in rate base for over 25 years before it is finally placed in service to ratepayers. We expect much better property management from SDG&E in the future, and we will continue to review the PHFU accounts carefully and, when appropriate, to remove items from that account when there is no plan for use in a reasonable time.

The final item to be covered before our consideration of working cash is Customer Advances for Construction (CAC). CAC represents funds supplied by customers to be applied toward constructing specific facilities. These funds are a deduction from rate base. Although the company and the staff have stipulated to a number of $46,717,000, UCAN argues that its evidence shows that the stipulated figure is understated by $4.269 million for electric and $856,000 for gas.

We will adopt the UCAN estimate. Both SDG&E and UCAN used a regression equation to estimate 1986. The UCAN equation which is based on compound growth is statistically superior because it produces a better fit between the data and the trend line. Also, the UCAN equation comports much more accurately to recent historical experience.

E. *Working Capital*

Most of the issues surrounding working cash have been disposed of in the A&G section dealing with compensating bank balances. The remaining issues deal with the accounts payable portion of construction work in progress, accounting treatment of materials and supplies, and gains on the sale of property.

The staff and SDG&E have agreed on the methodology for the estimate of the accounts payable issue. The difference between the parties lies with the latest year chosen as a base. Both the staff and the company utilized 1984 recorded figures, but the 1985 projected became available during the hearing. Use of the later information produces an increased ($1.0 million larger) working cash requirement. The staff argues that the later information is a selective update of convenience. We agree with the company that the later information produces a more accurate picture and will adopt its updated estimate.

The next issue, raised by the FEA, concerns the appropriateness of our current amortization treatment of certain gains SDG&E realized on the sale of its headquarters building in 1975 and its Encina Unit No. 5 in 1978. FEA argues that these gains constitute noninvestor sources of funds and should be subtracted from rate base to prevent investors from earning a return on amounts which they have not invested in the company. FEA is aware that we determined in D.90405 that the unamortized gain from the sale of Encina Unit No. 5 should not be used as a rate base deduction and that amortized property losses should not be added to rate base, but asks the Commission to reconsider this decision in light of SDG&E's improved financial situation. FEA also recommends that the Commission consider gains and losses on a case-by-case basis instead of systematically excluding them from making cash estimates.

[iii] We believe that our current treatment of gains on sale continues to be appropriate and will make no alterations at this time. With regard to Encina Unit No. 5, some elaboration may be helpful. Encina Unit No. 5 was built with shareholder funds, was never placed in rate base, and was sold to outside investors pursuant to a favorable lease back arrangement before it ever became operational. SDG&E recognized a gain of $23.4 million which is being amortized as a reduction in rental expenses over the initial term of the lease. As FEA pointed out, we have already determined in D.90405 that this gain should not be used as a rate base deduction.

In a recent decision concerning the sale of distribution facilities by PG&E to the City of Redding, we indicated that some financial rewards should be provided to shareholders in order to encourage management to obtain a fair price for utility properties being sold. Our treatment of the gains accruing from the instant transaction is in accord with this notion of incentives. SDG&E is being permitted to enjoy the use of the gains over the term of lease although ratepayers, through reduced lease payments, ultimately receive the benefits of the sale. This, in our opinion, strikes a fair balance between shareholders and ratepayers given the facts at hand. We reject FEA's recommendations.

The final issue is the accounting treatment of "materials and supplies". Currently, the entire amount of materials and supplies is included in rate base. PSD suggests that that portion of materials and supplies eventually going into construction be removed from rate base but be allowed AFUDC treatment. Staff proposed this in SDG&E's last general rate case but this proposal was not adopted because it did not appear well thought out and the ratepayer benefit was not shown. This situation has not changed. Staff shows that rate base would be significantly reduced but does not show what the other effects would be i.e., increased property taxes, increased depreciation, and the AFUDC-rate base effects. Thus, we do not know what the net effect of the proposed change would be and will not adopt this change until we are convinced that the net ratepayer benefit is significant.

IX. *Amortization and Depreciation Expenses*

The only item under this subject that has not been resolved is the difference relating to the amortization of the Materials Management Systems II (MMS II) expenses.

The MMS II is a software package purchased by the company in 1983. SDG&E requests authority to amortize the following over five years:

1. Feasibility Study	$ 79,000
2. Software Package	498,380
3. In-house Related Costs	1,175,620
Total	$1,753,000

The staff has excluded the in-house because those have been expensed previously. The staff does, however, acknowledge that the other costs can be legitimately recovered as requested by the company. The City of San Diego opposes any recovery arguing that such recovery constitutes retroactive ratemaking. We are persuaded by the staff that the recovery of the software package cost is not retroactive ratemaking. We will authorize recovery of the cost of the software over five years but deny recovery of the in-house costs and also the cost of the feasibility study as having been recovered in expenses earlier.

X. *Conservation and Load Management*

A. *Conservation*

In this application SDG&E requests $20,706,000 for conservation and load management activities. In arriving at their estimates for program funding parties generally agree that SDG&E has formulated its programs in accordance with our previous policy and directives. One exception is that in the view of some, SDG&E has over accentuated the weight of the nonparticipants test for cost-effectiveness and understated the weight of the Societal Test, and secondly, when viewing SDG&E's progress toward implementing demand-side programs, the Commission is somewhat disappointed with the company's lack of achievement and failure to meet goals, particularly when it is compared to the states' other major utilities.

[24] While our previous policy remains intact, the Commission takes notice of the equality between marginal and average costs for SDG&E electric service. By this we recognize that some demand-side programs which previously caused nonparticipants to bear program costs will now pass the nonparticipants test or at least cause less inequity. At this juncture, however, we will in general adhere to the Commission's “stay-the-course” policy for program funding.

There are two generic policy questions that can be resolved at this point. The first involves the level of program funding and the treatment of funds for certain programs that are winding down in the test year. The Public Staff recommends a cut in the 1987 and 1988 budgets for these programs and accordingly a cut in the overall spending for conservation. The company argues to maintain the overall spending level for conservation with the idea that certain monies can be reallocated and that any unspent funds will be carried over to reduce expenses in following years or be refunded to ratepayers. In light of the equality between marginal and average costs and our commitment to implement cost-effective demand-side programs, our stay-the-course policy will be adopted. The carry over/refund policy will apply to all conservation, load management, and other related programs.

[25] The second generic issue involves the level of management discretion which we will allow SDG&E in reallocating funds between programs. Currently, SDG&E is authorized to reallocate up to $500,000 without special permission and now requests that this limit be increased to $1.0 million. The staff recommends that the present limit remain in place. While we realize there is a longer time between rate cases, we feel that the next general rate case is the proper forum for a detailed review of SDG&E's programs. We will therefore adhere to our prior policy of $500,000 with the same conditions as we are now present.

For clarification, we wish to add that we will require SDG&E to file their March 31 and December 1 reports as previously directed.

Before proceeding we will attempt to put the request for funding into some perspective. We see first that the recorded past expenditures are as follows:

(83-000's)	*1983*	*1984*	*1985*	*1986 (Reg.)*	*1986 (Auth)*
Conservation	$24,760	$13,675	$13,713	$12,805	$9,483
Load Management	3,632	3,727	4,103	4,885	4,964
DSM	0	0	0	1,023	300
Other (CVR, etc.)	3,928	1,307	2,623	1,816	1,816
Total	32,320	18,709	20,439	20,706	16,563

The table below illustrates the request of SDG&E compared to the three positions of the staff on a program basis. This table will also be the framework for our discussion in this area.

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[26] We wish to reemphasize our commitment to assist SDG&E in refining their conservation programs and to support cost-effective demand-side options. (amounts will be in thousands of 1983 dollars unless otherwise specified).

Solar Rebate: *Requested*: $1,185; *Authorized*: $1,124

The staff recommends a cut of $61,000, representing advertising and seminars. We agree with the staff and generally agree that advertising for solar and conservation should be reduced. We were particularly impressed during public hearings in this case that SDG&E's ratepayers do not want to see more advertising than is necessary for these programs. With regard to cost-effectiveness, we wish to emphasize the obvious; solar domestic water heating is more cost-effective where electric water heating is in place. However, no new rebates for solar systems are being authorized herein. This funding is for meeting the existing solar rebate program commitments only.

AB 191: *Requested*: $1,700; *Authorized*: $0.0

AB 191 authorizes the California Energy Commission (CEC) to require among other things that utilities implement appliance incentive programs. The CEC has not yet done this. The Public Staff recommends that $1.2 million be allocated to this item, based on their judgment. The CEC has not provided specific cost-effective program proposals for staff to consider. Staff recommends the cut because California is due to receive up to $500,000,000 ($ one-half billion) from the Petroleum Violation Escrow Account (PVEA) which can be used to supplement CEC mandates or to retrofit residences. Public Staff suggests and we agree that SDG&E should seek PVEA funds whenever possible *before* using ratepayer funds for incentives. The staff and the CEC suggest that we mandate an appliance incentive program without official CEC action. We view incentive rebates positively because they provide energy and demand reduction hardware, which translate directly to cost savings.

The results of cost-effectiveness studies on incentive programs and staff's recommended funding levels are shown in Table 1. These incentive programs have been found to be quite cost effective and have relatively low program related costs.

TABLETABULAR OR GRAPHIC MATERIAL SET FORTH AT THIS POINT IS NOT DISPLAYABLE

We will deny funding for the AB 191 program at this time. If the CEC mandates incentive programs to use AB 191 funds with greater costs that for the incentive rebate programs we authorize, then SDG&E may file an Advice Letter requesting appropriate funding at that time.

8% Financing: *Requested*: $462; *Authorized*: $430

This program which provided low interest loans for residential weatherization will wind down in the test year. SDG&E requests expenses for inspection and administration for the loans granted in the last half of 1985. The staff believes that only the costs of loans granted during the last quarter of 1985 should be carried over. We agree with the staff that such costs should not lag more than three months and will adopt the staff cut of $32,000.

Direct Weatherization: *Requested*: $1,248; *Authorized*: $1,808

This program (DWA) was implemented in 1981 and continued in the 1982 and 1984 general rate cases, and is designed to provide free weatherization to low income and elderly customers. The company has shown and the staff agrees that the program is not cost-effective. Because of this deficiency and because other community funds are available, this program should be discontinued. The company proposes that the program continue but at a reduced level (from 4,000 to 2,000 installations per year) because of lack of demand.

On the grounds of equity and other intangible considerations, the direct weatherization program should be continued. We will authorize funding for 2,900 units with the direction that if sufficient demand develops, we will require that funds from other programs be allocated to this program to provide funding for up to 4,000. We view this program to be high priority among SDG&E's conservation programs.

Low-Income Refrigerator Rebate: *Requested*: 0; *Authorized:* $248

We will provide a refrigerator rebate program for low income groups, to be administered by local community base organizations, with loans from the California Energy bank if required. Where otherwise low income persons would buy used refrigerators with lesser efficiency and incur higher energy bills, this program will certainly provide substantial participant and societal benefits, as reflected in Table 1. We think that greater social efficiency and equity are provided by distributing these funds under a low income refrigerator incentive program.

Staff estimates that the costs for this subsidy equate to $100 each for 2,000 new refrigerators and administrative costs of $48,000 for a total of $248,000. It is suggested that SDG&E obtain another $100 per refrigerator of matching funds from the CEC through AB 724 or PVEA funding. Also, refrigerator manufacturers or dealers may contribute $50 - $100 per refrigerator for promotional efforts to increase sales. Public housing authorities may also allocate funds for refrigerator replacements through their normal operations. SDG&E may wish to review SCE's very successful program as an example.

We will expect a full and complete analysis of this program in the next general rate case. For *non* low income customers we do not now establish a refrigerator rebate program but will encourage the company to request use of any remaining funds for such a program.

Multi-Family Weatherization: *Requested*: 40; *Authorized*: 40

The objective of this program is to provide incentives or rebates ($200 per unit or $0.30 per square foot of insulation, whichever is less) to customers on the costs of weatherizing multi-family units. Customers select a contractor who then submits a bid to SDG&E for eligibility review and job approval. This program was [sic].

Master Meter Conversion: *Requested*: 10; *Authorized*: 10

This program is designed to encourage multi-family customers to convert their master meters to individual meters or submeters. Customers are offered a conversion feasibility study and are provided with contractors' lists and other conversion procedure assistance. The Public Staff has re-evaluated this program and found, among other things that the program is no longer cost-effective, and there is low participation due to high initial costs. We will allow the requested amount.

Commercial Demand Reduction: *Requested*: 480; *Authorized*: 720

This program will encourage customers with $200,000 incentives (rebates) to install load reduction equipment that will lower their peak demand or shift their demand to off-peak. Cash rebates are effective tools in stimulating customer installation of energy saving premium hardware that could provide persisting savings in long term. Table 1 shows the results of Cost-Effective Studies of the Incentives Programs by program elements for the AB 191 Program. The typical program elements are: Solar Films, Skylights, Dimmer Systems, Indirect Evaporative Cooler, Thermal Energy Storage (TES) and Energy Efficient Refrigerators. Qualified customers will be contacted and encouraged to make financial commitments that will reduce their load. This new program is very cost-effective from all perspectives and of significant interest to the Commission. To market the Commercial Demand Reduction Program effectively, it is necessary to link it to the Non-residential Audit Program. The Non-residential Audit Program is essentially an evaluation of energy savings potentials and one in which hardware measures are recommended and implemented at customers' expense. Participating customers must install the recommended no cost or low cost measures before being eligible for cash rebates.

Program Support: *Requested*: 45; *Authorized*: 45

There were no issues contested with regard to this program. We will adopt the company estimate supported by the staff.

B. *Customer Energy Management Assistance*

Audits/Energraf: *Requested*: $975; *Authorized*: $802

SDG&E requests funding to perform residential energy audits and Energraf analyses upon request. PSD argues that because the audits are not cost-effective and no longer mandated under the federal RCS program, that funding should be reduced to $802,000. We will adopt Staff's recommended funding level. PSD points out that the customer service aspect of this service can be satisfied in a more cost-effective way by use of mail and telephone contacts, as recommended by the Ernst & Whinney audit.

Brochures: *Requested*: $503; *Authorized*: $262

The staff recommends cuts of $92,125 for advertising, $73,700 for mass mail, $44,600 for direct mail, and $30,700 for a proportional cut in labor. These recommendations are based on the idea that conservation awareness is such that need for such advertising is substantially reduced. Also, the program fails the nonparticipant ratepayer cost-effectiveness test and barely passes the societal test. We agree with the staffs and will adopt the staff recommended level for this program.

Energy Information Center: *Requested*: 160; *Authorized*: 107

While PSD supports this program to provide information on request, it argues that the promotional costs are excessive. PSD recommends a reduction in radio and bill advertising ($53,000) which we will adopt. This will improve the cost-effectiveness of the program, which currently passes only the participant test.

Nonresidential Audits: *Requested*: $1,383; *Authorized*: $1,383

The objective of this program is to help nonresidential customers identify inefficient uses of energy in their businesses and to encourage cost-effective improvements. The staff fully supports this program which complies with state and federal mandates. The staff recommends a cut based on general productivity improvements. The staff cuts will be denied.

Agricultural Energy Management: *Requested*: $92; *Authorized*: $70

The staff recommendation is to keep this program at roughly the present level. The SDG&E estimate envisions program expansion. The company failed to show sufficient need for program expansion. The staff level will be adopted.

Program Support: *Requested*: $454; *Authorized*: $424

While SDG&E has purchased a data system service for $105,000, they have requested an additional $30,000 in program support for consulting services on software and computer system development. PSD has disallowed this expense, and agrees with the remaining $424,000 test year estimate, which we will adopt.

C. *Load Management*

Thermal Energy Storage: *Requested*: $2,675; *Authorized*: $2,675

SDG&E began implementation of TES in 1984 and reported that it effectively reduces 85 percent of peak period electric demand for airconditioning. TES is very cost-effective from all perspectives. SDG&E proposes to install 60,000 ton-hours of commercial TES; approximately 93 percent ($2,500,000) of this budget is for inducements. Staff believes that a minimum of 10 MW of load reduction should be obtained from TES in 1986, and believes that his load reduction is necessary to justify SDG&E's proposed budget for TES. We agree and will adopt the requested amount.

Commercial Load Controllers: *Requested:* $40; *Authorized*: $40

SDG&E has proposed spreading $40,493 to install 20 load controllers. Its goal in the first year is to achieve a 600 Kw load reduction. The program offers participants the advantage of choosing which appliances to turn-off in order to reduce their electric load. If SDG&E can meet its load reduction goal at its proposed funding level, it will be by far the least expensive of SDG&E's load management programs.

Residential Peakshift Airconditioning: *Requested*: 1,451; *Authorized:* 1,563

The CPUC and CEC staffs jointly recommend 1986 funding for this program of $1,562,763. CEC witness Jacobsen testified that the CEC considered all evidence related to changing the shedding strategy for residential peakshift and could neither endorse nor explain SDG&E's claim for added expenses. In order to develop a more effective program, SDG&E proposes to have customer reaction surveys and special peakshift studies conducted. The proposed cost of these surveys is $225,000. Currently the program is not cost-effective in its present form. SCE and PG&E indicate that this type of program can be highly cost-effective, but only when the shed strategy (100% cycling) is used. According to staff, SDG&E should attain an average of 1.4 Kw per participant using the-shed-strategy, which is comparable to the load drops obtained by SCE and PG&E. Currently there are 21,358 customers in the program. Staff calculates that a 16 MW load reduction can be gained in 1986 if 15,000 customers are transferred to load shedding. The staff and this Commission agree that special peakshift studies are unnecessary because such studies will not make the program more cost-effective. We direct SDG&E to implement the residential peakshift as a load shedding program exclusively, because this strategy has shown to produce very cost-effective results. Therefore, we direct SDG&E to offer only the shedding strategy to current and future participants. $312,000 is authorized for additional incentive payments and the request for $200,000 for special peak-shift studies is denied.

Residential Peakshift Water Heating: *Requested*: $69; *Authorized*: 0

The current peakshift water heating program is clearly not cost-effective. SDG&E, however, proposes to spend $68,850 to maintain the program. The reported load drop is only .1 Kw per customer. We support the staff's recommendation that the program be eliminated.

The ALJ took official notice of CEC Order No. 85-047-01 which mandated certain load management actions on the part of SDG&E. The CEC order provides that $1,562,763 is required for the residential peakshift program (air conditioning) and $0 for the residential water heater peakshift program. We acknowledge the CEC's order and have authorized this amounts.

Commercial Peakshift: *Requested*: $235; *Authorized*: $85

The staff recommendation is to keep this program at the same level of spending as 1985. SDG&E argues that some of the functions to be performed in 1986 were previously funded through RD&D. The CEC supports the staff estimate. We will adopt the 1985 level of funding and program activity and authorize $85,000.

Group Load Curtailment: *Requested: $0;* Authorized*: $100*

SDG&E at the time the opening briefs were filed was requesting $175,000 for this program, but has since dropped its request totally. At the same time, both the staff and the CEC support this program at the $100,000 level. The program is designed to have a group of industrial/commercial customers shift summer time peak usage on an integrated basis. The program is a CEC proposed, but not mandated, program. Other major utilities have similar programs with some success.

Community Energy Management: *Requested*: $0; *Authorized*: $100

The Community Energy Management Program is a load management program in which entire communities are involved in a campaign for reducing summer time peak energy consumption. A major objective of the program is to make communities more aware of load management. Incentives for the program are generally in the form of energy conservation goods or cash. This program is proposed by the staff and by the CEC staff. The program is not proposed nor supported by SDG&E.

Staff makes the following recommendations:

1. The test program should operate for a duration of two summer seasons and program effectiveness should be demonstrated before expanding the program to other communities.

2. Community population should be between 20,000 and 80,000.

3. Community should have significant peaks in summer load profile which are amenable to load reduction.

4. At least 90% of energy usage of both the test and control communities should be metered separately from that of surrounding areas.

5. SDG&E should be authorized a funding level of $100,000 in 1986 for CEMP.

We will adopt staff's recommendations with one proviso; SDG&E should attempt to locate communities for the program where ideas about load management are expected to be understood and acted upon, such as a college community. This will make attainment of the objective, which is to make communities more aware of load management, more easily attainable.

Load Management Goals

[27] Staff has testified to their concern about the high cost and low benefits of load management programs reported by SDG&E. SDG&E is also vague about reporting expected program goals for test year 1986. In only two of five programs has SDG&E given a load reduction goal for 1986. The Commission is more disturbed about SDG&E's failure to propose any positive steps that will promote program cost-effectiveness. The utilities proposals are to conduct customer reaction surveys, marketing research, and equipment studies. Staff argues that it “does not believe that any of these proposals will benefit non-cost-effective programs and considers it poor management.”

The staff recommends that SDG&E face a penalty if specified load management goals are not met. Specifically, the staff provide the following reduction goals: Residential Peakshift Aircondition, 10 MW; Thermal Energy Storage, 10 MW; and Commercial Load Controllers, 1.8 MW. Staff has performed detailed calculations of expected load reductions and necessary incentive levels for each of these three programs. The recommended penalty is keyed to peaker plant capacity which would theoretically replace the portion of the load management reduction goal which is met, and serves as a reasonable risk allocation device for the ratepayer funding of this supply option. (Op. Br. pg. 105.)

We will not adopt the staff recommended penalty mechanism at this time, but do adopt the staff's goals and direct our staff to review the future progress of SDG&E's attainment of the above load management goals. In the future, if SDG&E seems uncooperative or disinterested in carrying out the Commission's intent regarding load management programs, we will consider initiating a penalty mechanism.

Program Support: *Requested*: $415; *Authorized*: $401

The staff recommends a $14,000 cut in this area representing in its judgment excess travel and consultant expenses. We will adopt the staff recommendation as a general belt-tightening measure.

D. Ancillary Facilities and Support: *Requested*: $1,294; *Authorized*: $1,150

The program element includes the cost of management and support personnel, etc. PSD has reviewed these expenditures in substantial detail. We will adopt the staff recommended funding level.

Other Ancillary: *Requested*: $2,819; *Authorized*: $1,000

The company is requesting funds for major research regarding its customers' usages, preferences, and load shapes in an attempt to better understand the potential effectiveness of load management and conservation programs. Some of the research areas are:

1. Load shape, TOU equipment evaluation, customer needs, rate menu commercial market research.

2. Demand elasticity and appliance saturation.

3. Curtailable/interruptible service, agricultural TOU, standby service.

SDG&E requests these funds because it has recently reevaluated its entire program in this area and finds that it has not maintained nearly the same base of knowledge as the other utilities. It has implemented conservation and load management programs when mandated by regulatory agencies without proposing innovative programs of its own.

Staff proposes that we reduce the authorized amount to $1.39 million. While we agree that the utility has little need for research in these areas, we have a number of concerns. First, we are concerned about the accuracy of SDG&E's estimates of the actual energy and demand savings from demand-side programs. We suggest that some of these funds be used for this specific area of program evaluation.

Second, we are concerned about SDG&E's apparent lack of interest in TOU programs in general. While the other utilities in the state firmly embrace the use and application of TOU rates, SDG&E seems to need more money for research and evaluation. We suggest that SDG&E develop and propose a plan to more effectively market TOU rate schedules for customers that can significantly effect the system load shape through their behavior. We further suggest that funds from program evaluation/research be used to develop these types of proposals for the Commission's review.

And third, the Commission suggests that this category of funding be used to forward the implementation of demand-side programs which are known to be cost-effective and provide substantial ratepayers benefit. Therefore, research into areas which do not already show significant economic promise should be limited; evaluation and implementation of cost effective programs should be the focus of SDG&E's efforts. SDG&E should work closely with our Evaluation and Compliance Division's Energy Branch staff in the development of its 1987 programs using the benefits of its research studies in 1986.

We will authorize $1,000,000 for further program evaluation.

E. *Demand Side Management*

Demand Side Management: *Requested*: 1,023; *Authorized*:

300

This program is supposed to be separate from but integral to the research and program evaluation areas described above. A major goal of demand side management (DSM) is to increase energy sales and increase load factors (average demand divided by peak demand). Programs variously described in the DSM portfolio include strategic conservation, strategic load growth, peak clipping, load shifting, valley filling, and "flexible load shapes." The name for this program is apparently chosen to disguise a "marketing" strategy.

Staff list a number of factors to be considered in assessing SDG&E's request. SDG&E appears to have nearly doubled this request since the company filed its NOI. SDG&E's research budget is planned to provide studies closely related to DSM. And, the DSM proposal for 1986 represents almost one-fourth of SDG&E's budget for customer energy management, compared to 4.9% for SCE and 4.7% for PG&E. Moreover, the Ernst & Whinney audit recommended a one-time expense of $30,000 and an annual expense of at least $60,000 to pursue DSM.

The staff also highlight the obvious conflict between load building, using DSM, and conservation. There is also some question whether DSM would actually decrease rates. As the staff points out, it may be short-sighted to allow an overbuilt utility to promote energy usage to lower its rates.

We find that the staff's concerns convincing, and accordingly authorize $300,000 for DSM.

F. *Other Conservation/Load Management Issues*

[28] There are three remaining conservation related programs to be discussed: 1. streetlight conversion; and 2. conservation voltage regulation. The staff recommends substantial cuts in these programs and 3. Seasonal Pilot Light program.

The streetlight conversion program involves the replacement of existing streetlights with more efficient lamps. The staff recommends cuts in rate base for this program because it shows that this program will be completed in 1985. We will adopt the staff estimate for rate base. Another difference is the cost of the lamp conversion. The staff shows that the cost of lamp conversion kits for SDG&E are much higher due to special design requirements. The staff recommends a figure much more in line with the statewide costs. We will adopt the staff estimate.

The second program is the conservation voltage regulation program. This program has been in place for many years and the easy fixes have been made. The staff recommends that a five year historical average be used as the yardstick for capital in place due to SDG&E missing its most recent goals. The staff estimate will be adopted.

The third program is the seasonal gas furnace pilot light turnoff and relight program which was somehow overlooked in this proceeding. The program has historically been carried out at about $10,000 per year as discussed in SDG&E's March 31, 1985 report on Calendar year 1984 conservation activities. A similar budget for 1986 will fund one bill insert and one bill message in the spring of each year to notify customers to turn off their furnace pilots and a bill insert in the fall to instruct the customers to relight their pilots safely. This program should be financed by discretionary funding allowed in this decision.

XI. *Gas Expenses*

There remains only one contested issue related to gas distribution or gas expenses. All other issues have either been stipulated to or resolved in other sections of this decision.

[29] The management audit report recommended that SDG&E study the merging of the Gas Servicemen and Turn-on Meterman functions. The staff estimate includes a savings of $327,000 for the implementation of this recommendation in the test year. SDG&E has agreed to the study and generally agrees with the idea, but argues that such a proposal would have to be the subject of labor negotiations to take place in 1987 before the concept could be implemented.

The idea of the merger of functions is obviously a good one, but also one that cannot be implemented before 1988. We will, therefore, impute only one-third of the savings for the test year.

The last remaining issue in gas distribution expenses concerns the number of drafters. In the 1984 rate case decision, we authorized SDG&E 14 positions. The utility, however, utilized only 10 for most of the interim period. SDG&E now shows a workload that will justify the 14 positions. The staff position is that since it underspent in this category since 1984, it really does not need the 14 positions. SDG&E has filled all the positions and shown a legitimate need for the 14 positions. The company estimate will be adopted.

XII. *Rate of Return*

A. *Recommendations of the Parties*

In the present proceeding, rate of return presentations were made by SDG&E, the Commission staff, the Federal Executive Agencies (FEA) and the City of San Diego (San Diego).

By Commission Resolution ALJ-151, rate cases were changed from a two-year interval to a three-year interval. SDG&E and staff have included a 1988 recommendation which the FEA and San Diego did not. The appropriate treatment for attrition, particularly the second year attrition or the third year of the rate cycle, has yet to be determined and hearings before the Commission were held during mid-1985.

The respective recommendations are as follows:

1. *SDG&E*

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SDG&E's overall cost of capital recommendation would be reduced somewhat if a proposed holding company application which would alter the capital structure slightly is granted.

2. *PSD*

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3. *FEA*

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4. *City of San Diego*

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B. *Capital Structure*

The structures proposed by SDG&E and staff are almost identical:

	SDG&E			*Staff*		*(Adopted)*
	1986		*1987*		*1988*	*1988*
Long-Term Debt	43.39	42.21	-	43.0	42.0	40.50
Preferred Stock	8.82	8.45	-	9.0	8.5	8.50
Common Equity	47.79	49.34	-	48.0	49.5	51.00
Total	100.0	100.0	100.0	100.0	100.0	100.00

[30] FEA and San Diego adopted the staff capital structures, which are based on recorded information as of December 31, 1984, and changes estimated to occur in the capital structure during 1985-1988. While the common equity ratio has averaged approximately 38.00% over the ten-year period (1975-1984), it has steadily increased and has averaged approximately 43.00% over the past few years. The increase in the equity ratio over recent years and the estimated build-up projected for the near future should provide a positive contribution towards SDG&E's financial health. These higher levels of equity should also help to sustain or improve interest coverage levels and provide SDG&E with additional financial flexibility to satisfy its future capital requirements, positive factors to be considered in setting a fair return on equity.

SDG&E also states that the Commission should recognize the impact of long-term capital leases, although it makes no specific adjustment to increase debt and decrease equity to reflect their impact. The staff's capital structure which we adopt will provide sufficient equity to mitigate the effect of leases.

SDG&E's nuclear fuel lease and other property leases meet the criteria requiring capitalization under an accounting standard issued by the Financial Accounting Standards Board (FASB): however, they are currently treated as operating leases for ratemaking purposes and accordingly have not been reflected on the balance sheet.

The staff believes the current practice of not including leases as a component of the capital structure is consistent with the current treatment of leases as an operating expense. Inclusion of leases as a component of the capital structure may eventually be required for financial statement purposes (FASB 71); however, the staff recommends that it only be considered for ratemaking purposes after a thorough analysis.

San Diego and UCAN express concerns that the increasing proportion of equity in SDG&E's capital structure will increase the company's capital costs without any significant offsetting reduction in the cost of debt due to upgraded bond ratings or increased investor confidence. These parties contend that we should take the equity increases proposed by the company into account when considering return on equity and make systematic downward adjustments in the return on equity over the rate case cycle to correspond to increases in the equity ratio over this period.

Although we are also concerned about the increase in the equity component of SDG&E's capital structure, we will not at this time attempt to establish a formula correlating an increase in equity with any specific decrease in return on equity. We note that the upcoming changes in the FASB treatment of capital leases may confound our interpretation of any signals from the financial community concerning such a systematic adjustment. Because we believe that SDG&E's increasing equity may well present a serious problem in the future, however, we direct the staff and the company to address this issue thoroughly in the next appropriate rate case.

C. *Cost of Debt*

Long Term Debt Costs	*1986*	*1987*	*1988*
Staff	10.47%	10.38%	10.29%
SDG&E	10.57	10.59	10.58

FEA and San Diego use the staff estimates.

SDG&E assumes one new $50 million debt issue in 1986 at 13.75% cost, one in 1987 at 13.25% cost, and one in 1988 at 13.00% cost. The staff assumes only a single $50 million issue in 1987 at 13.00%. The staff financial assumptions are based on SDG&E's revised financial plan and are a more accurate reflection of SDG&E's current financial assumptions.

Staff and SDG&E estimated debt costs use Data Resources and Blue Chip Financial Forecasts of AA utility bonds, which must be adjusted to reflect SDG&E's single A rating. The staff used a 50 basis point adjustment based on 1975-1984 based rate spreads between AA and A rated debt. SDG&E used 63 points. FEA used a third forecast, the February 1985 Chase Econometrics, *U. S. Macroeconomic Forecasts and Analysis* of AA costs, which was adjusted by 60 basis points for SDG&E's single A rating, which led to assumed costs of 13.20% for the 198 issue. The FEA analysis led to the same debt costs as those estimated by the staff.

During the September update hearings, both SDG&E and staff reflected recent changes in SDG&E's financing plan. SDG&E issued $100 million of 9.25% Industrial Development Bonds (IDB's) in August, 1985. The proceeds from this issue were used to (1) retire $35 million of foreign term loans originally estimated to be retired in 1986, and (2) redeem the $75 million 13.625% Series T bonds. Additionally, SDG&E has authority to issue an additional $50 million of IDB's. Both SDG&E and staff revised their estimated financing cost for 1987 to reflect IDB financing at 9.50%.

With respect to our policy of reflecting the most recent financing costs, we will recognize SDG&E's most recent financing of a 5.625%, $35 million pollution control bond during December, 1985. The proceeds from this issue were used to refund a portion of the 12.875% Series Z bond issue.

The overall impact of all the updated financings results in the following changes to the staff estimate of the embedded debt cost:

Long-Term Debt Costs19861987

1988	Staff	10.01%	9.78%
9.59%			

We will adopt the staff estimate of the embedded debt cost.

D. *Preferred Stock*

The preferred stock costs are shown as follows:

StaffSDG&E

SDG&E Revised	1986	9.64%	10.33%
10.06%	1987	9.67	10.10
9.56	1988	9.69	10.09
9.54			

The differences between the staff and SDG&E are attributable to the treatment of the gain realized on the retirement of the $7.325 series and half the $8.25 series during December 1983, since no new issues are projected in the forecast period. SDG&E revised its treatment in Exhibit 26 to reduce the difference with the staff, which is attributable to the timing of the capture of the gain on behalf of the ratepayers. The staff treatment gives proper consideration to the ratepayers in that the effective dividend rate is reduced from a level on which previous rates were set to a level which fully reflects the gain realized on the retirement of preferred stock. Also, the staff adjustment is consistent with that made to recognize the premium paid for refunding portions of the Series S and Series V long-term debt issues during 1983. The staff estimate of preferred stock is adopted.

E. *Return on Equity*

Our objective is to authorize a return to common equity owners that will be commensurate with market returns on investments having corresponding risks during the test period. In the last SDG&E general rate case we outlined the three major considerations which guide us in accomplishing this objective:

First, we believe that, all other things being equal, the cost of equity capital varies in the same direction as changes in the general level of inflation and interest rates. Although the absolute magnitude of that relationship or “risk premium” is an issue of controversy, the general principle is not only consistent with financial theory, but also acknowledged by this Commission and parties to this and prior rate of return proceedings.

Second, we recognize that the market cost of equity capital for a particular company reflects other risks, such as the exposure of a utility's earnings to variability in fuel costs, sales levels, as well as uncertainties regarding the cost recovery of prior capital investments. Hence, our determination of an appropriate rate of return must also take into consideration the extent to which these risks have abated, increased or remained unchanged, and the probable direction of change during the test year period.

Finally, we believe that the judicious application and interpretation of financial models can aid us in quantifying the overall balance of these risks, and the market cost of equity capital during the test period. It must be emphasized, however, that the models themselves may not accurately reflect all of the intricacies of financial markets. Further, the assumptions used in applying a financial model or formula must be carefully evaluated for reasonableness before this Commission places substantial weight on the numeric results. (D.83-12-065, p. 91c.)

In this proceeding, SDG&E, staff, FEA, and San Diego presented testimony on return on equity. UCAN, although it did not present direct testimony, did cross-examine other parties and participate fully in the discussion of this issue.

The parties' recommendations for the return on equity appropriate for SDG&E in the 1986 test year are as follows:

SDG&E

16.5%	Staff
15.25%-15.75%	FEA
No more than 15.25%	San Diego
No more than 15% (If no change in ROE in the attrition years.)	UCAN
15%	

We will now evaluate SDG&E's return on equity in light of the considerations outlined above.

1. *General Economic Indicators*

Since the last SDG&E general rate case decision in December 1983, interest levels have come down significantly and inflation has reached its lowest level in many years. The table below, compiled from evidence presented in the proceeding and a recent business publication of which we take official notice, shows the steady downward trend in interest rates.

Interest Rate Trends
From December 1983 to December 1985

	12-20-83	*3-1-85*	*5-25-85*	*12-10-85**
Prime interest rate	11%	10.5%	10%	9.5%
Discount rate	8.5	8	7.5	7.5
Federal funds market rate	9.49	8.72	7.75	7.87
3-month Treasury bills	8.93	8.36	7.28	7.19
6-month Treasury bills	9.12	8.53	7.43	7.26
1-year Certificates of Deposits	10.5	9.85	8.15	8.05

*Wall Street Journal, Tuesday, December 10, 1985, p. 46.

SDG&E's witness Haney states that general economic conditions are “slightly to moderately more favorable” than those prevailing in 1983. Other parties believe this is an understatement.

2. *Specific Changes in SDG&E's Financial Status and Risks Since the 1984 Test Year General Rate Case*

There has been a dramatic improvement in SDG&E's overall financial condition since the last general rate case decision in December 1983, and a substantial reduction in the specific risks faced by the company. In addition, the evidence shows renewed investor confidence in SDG&E.

The table below, with the 1983 and 1984 figures taken from SDG&E's 1984 Annual Report, reveals the improvement in SDG&E's financial health since 1983.

SDG&E's Financial Data Showing Changes Since 1983

Financial Indicator		*1983*	*1984*	*1985*
1.	Equity as % of Capital	42.17%	44.01%	47.33% (projected)
2.	Bond rating (Moody's)	A3	A2	A3 (June 20)
	(Standard & Poor's)	A-	A+	A+
3.	Market price per share (December 31)	$20.12	$22.50	$27.57 (June 30)
4.	Market to book ratio	106%	117.45	138% (June 30)
5.	Pre-tax interest coverage	3.66	3.88	
6.	Construction as % of capitalization	11.3%	7.5%*	
7.	% of construction funds internally generated	49%	120%*	
8.	AFUDC as % of earnings**	49%	15%*	

*Reflects completion of SONGS 2 & 3 and the South West Power Link.

**Reflects quality of earnings.

SDG&E claims that its overall business risks have merely changed, but not declined since its last general rate case, listing the following risks it faces in coming years: (1) the implications of the rapid growth in SDG&E's service territory; (2) the risks associated with SDG&E's increasing reliance on purchased power to meet demand growth; (3) the continuing risks associated with SDG&E's involvement in nuclear power generation; and (4) the increase in regulatory risks associated with the inclusion of a second attrition year in the rate case cycle, the increase to an 8% risk-sharing level for the annual energy rate (AER) in February, 1984, and the Commission's expression in D.84-12-068 (SCE 1985 test year rate case) of a general policy of shifting more risk to shareholders.

In its 1984 Annual Report, however, SDG&E presented a much brighter view of its future. Granted, statements by management to shareholders touting their success are always to be read in view of their purpose - to attract and retain investors. However, we suspect that the company's confidence is founded on objective facts, such as the financial data reprinted from the Report, above. Those same indices should generate investor confidence as well.

On the one hand, SDG&E asserts that its decision to rely on purchased power actually increases the risk it faces because the possibility that increased capital will be needed to meet capacity needs in the 1990s is a substantial risk factor that will be considered by investors and rating agencies. On the other hand, the company states that it has successfully met the challenges of a rapid growth in new homes and informs shareholders with confidence that the company will no longer build any more large, central station generating plants because the company anticipates that the purchase of power, rather than the construction of additional generating capacity, will continue to be an attractive option in the years ahead. The company notes that in 1984 there was a great deal of power available for purchase from other utilities and that there is likely to be even more power available, from both utilities and alternative energy producers, for the next 15 years.

Elsewhere in its Annual Report the company describes other factors which should enable it to meet future energy demand without the need for capital intensive plant construction. These include a nationwide shift away from the energy intensive production of basic goods to less energy-intensive types of industry and decreased demand as a result of higher, nuclear-era rates. As a result, SDG&E believes that energy will become available for it to purchase.

The investment community has reacted favorably to the company's decision to rely on purchased power. In its recent report upgrading SDG&E's first mortgage bonds from A2 to Aa3, Moody's Investors Service observed that the company's power supply should be adequate for the foreseeable future, and noted with favor the company's power purchases.

The positive reception SDG&E's power purchases plans received from a bond rating firm such as Moody's is especially significant in light of the fears expressed by SDG&E witness Meyer that while common stockholders are likely to favor plans which reduce the risks a utility faces with regard to large scale construction projects, bondholders may be apprehensive about the long-term risks which might result from a lack of adequate future generating capacity. We believe that the “real world” reaction of Moody's gives us a better idea of investor expectations than does the speculation of SDG&E's witness. Even if SDG&E's fears are justified, we are not inclined to require today's ratepayers to reward the company with a higher return on equity simply because it made an admittedly risky business decision with uncertain long-term consequences.

None of the risks of SDG&E's involvement with nuclear generation have increased since the last general rate case decision. On the whole, with the completion of SONGS 2 & 3, and the Commission's decision to allow traditional rate base recovery for the construction of these units, SDG&E's nuclear related financial risks have been reduced substantially. SDG&E management does not expect that the overall effects of our SONGS 2 + 3 prudency review and our SONGS 1 sleeving decision will be material to the company's financial condition. (1984 Annual Report). We note that the investment community does not seem unduly concerned over SDG&E's nuclear future, and that Moody's Investors Service explicitly acknowledged the possibility of a $150 to $200 million disallowance of SONGS 2 & 3 construction costs at the same time it upgraded the company's rating to Aa3.

SDG&E cites the 3-year rate case and increase of AER to 8% as reasons why it should be compensated for higher regulatory risk. Moody's notes that balanced regulation, among other things, has enabled the company to improve its performance and to meet specific financial objectives.

We concur with the more benevolent view of our regulatory mechanisms since we strongly believe that the attrition year adjustments and our variety of balancing accounts have largely insulated utilities from the risks of the marketplace. In addition, we note that although the AER increase to 8% may not have been implemented until early 1984, it was clearly considered during SDG&E's last general rate case proceeding, and thus cannot be fairly considered to represent a “new” regulatory risk. We therefore give little weight to SDG&E's claims of increased regulatory risks.

Reading SDG&E's rate case claims of sustained or increased business risks in light of its assessments of these same risks in its 1984 Annual Report, we sense a certain ambivalence toward the situations surrounding these risks. On the other hand, the company's overall view of its future financial outlook is optimistic. The Annual Report states that in the 1980-1984 period the company provided an annual overall return to shareholders of 25.19%, which put the company in the top quarter of the electric utility industry, and notes management's pledge to keep it there. There is no doubt that SDG&E's financial health has improved and that its specific risks have declined since the last general rate case decision.

3. *Financial Models*

SDG&E, PSD, FEA, and San Diego presented testimony regarding the discounted cash flow (DCF), comparable earnings, and risk premium methods for quantifying SDG&E's cost of equity.

a. *DCF*

SDG&E, staff, and FEA place primary reliance on the DCF model in the quantitative analysis of SDG&E's cost of equity. The DCF model is based upon the assumption that the current market price of a share of common stock equals the present, or discounted, value of the expected future stream of dividends and capital gains from the sale of the stock. The discount rate which equates the market price of the stock to the present value of the anticipated dividends and capital gains represents the expected return on equity. In its simplest form, the model assumes that a company has a constant dividend payout ratio and earnings which will grow at a constant rate. The basic DCF formula may be expressed as follows:

Expected return on equity	=	expected dividend	expected growth
		yield (dividend/	rate of dividends
		price) at time of	
		stock purchase	

The current dividend yield can be directly observed in the marketplace; however, an assumption must be made regarding the appropriate period of observation. The dividend growth rate expected by investors is more difficult to determine, as one must evaluate the company's future earnings performance.

SDG&E developed a dividend yield of 10.7% by applying to forecasted bond rates a regression equation correlating past monthly Aa bond yields with the company's actual dividend yields for the previous month. During the proceeding, SDG&E's reduced this estimate by 50 basis points to reflect recent reductions in interest rate projections for Aa utility bonds. Staff used the 9.77% average dividend yield for the six months beginning August 1984 and ending January 1985 as a reasonable measure of investors' current expected dividend yield for SDG&E's common stock. FEA derived two estimates of the coming years dividend yield, one, 9.7%, based on the application of a growth estimate based on two years of historical data to the company's average stock price from December 1984 to March 15, 1985, and the other, 9.8%, based on the application of the same growth estimate to the spot price of the company's stock on March 15, 1985. FEA believes the 9.7% dividend yield based on the average stock price is more reliable.

SDG&E criticizes the dividend yield estimates of staff and FEA as being unreliably based on short-term data from a period of volatile market activity. FEA contends that since SDG&E first presented its regression equation in its rate case application, it has performed abysmally. FEA also contends that SDG&E's use of projected bond yield implies in this case a decline in the price of stock in coming months and thus violates the basic “constant growth rate” assumption of the DCF method as used by the company, which implies that stock prices will grow over time. FEA points out in its brief that staff's dividend estimate would be lower if it relied on data more recent than August 1984 to March 1985. We note that the same logic would apply to its own estimate based on data from roughly the same period.

The most difficult aspect of implementing the DCF method is the estimate of the growth rate. There are essentially three methods that may be used to estimate the growth rate: (1) an analysis of historical growth rates; (2) projections of analysts: and (3) the calculation of a sustainable growth rate by use of the formula where the growth rate is calculated by multiplying the expected retention rate times the expected return on book equity. If a company's past growth trend has been erratic, it is difficult to project future growth based on historical data.

SDG&E based its dividend growth projection of 6.8% on the most recent five-year compound growth rate. Staff used a ten-year compounded growth rate as the foundation for its dividend growth estimate of 5.5% to 6% believing that SDG&E's recent dividend growth (during a period of market volatility) exceeds the ten-year growth rate significantly and thus artificially inflates future dividend growth expectations. FEA considered all three methods of determining dividend growth and arrived at a range of growth rates of 4 to 6%.

While San Diego and UCAN did not present their own DCF calculations, they did cross-examine witnesses and participated fully in the discussion of the DCF method. Both San Diego and UCAN criticize this method as being too heavily dependent on subjective input. The controversy between SDG&E, staff, and FEA over the DCF inputs used in this case shows that there may be some merit to this position. As FEA notes, however, all the financial models used for estimating returns on equity which were presented in this case are highly influenced by the inputs chosen; unless we are to abandon those quantitative methods altogether, we simply must apply our best judgment to determine which inputs we believe are most appropriate.

The following table summarizes the DCF estimates provided by the parties:

DCF Estimates

Party	*Expected Dividend Yield*	*Expected Growth Rate*	*Total DCF Estimate*
SDG&E	10.2%	6.8%	17 - 17.7%
Staff	9.77	5.5-6	15.27 - 15.77
FEA	9.7	4-6	13.7 - 15.8

We are not completely satisfied with any party's overall DCF presentation. We found SDG&E's approach the least persuasive, since the company's own return on equity recommendation of 16.5% is substantially lower than the low end of its DCF range. While we feel that the staff's six-month dividend yield average provides the most appropriate indicator of current investor expectations in the absence of more recent data, we believe that FEA's multifaceted estimate of dividend growth is preferable to the more simplistic approaches of SDG&E and staff. Adding staff's dividend yield estimate of 9.77% to FEA's dividend growth estimate of 4-6% yields a cost of equity of from 13.77 to 15.77%, a range we believe is appropriate.

b. *Comparable Earnings*

The basic principles underlying the comparable earnings approach are (1) an investor should be able to earn a return on a given utility investment comparable to that available on alternative investments of similar risks, and (2) the return should allow the utility to compete for equity capital and maintain its financial integrity. The major problem with this approach is the difficulty in determining which companies are truly comparable. Most parties use bond ratings as a proxy for overall risks, despite the fact that utilities with similar ratings may have quite different specific risks which may be considered by investors.

SDG&E, staff, and FEA apply their DCF methodologies to various groupings of single A-rated utilities to arrive at cost of equity estimates of 16.5-17.3%, 14.85-15.65%, and 14.1-15.4%, respectively. San Diego evaluates the rates of return allowed various groups of A-rated utilities to arrive at a cost of equity estimate for SDG&E of 15.075% in 1986, declining to 14.9% in 1987. FEA determined that the average return on equity allowed A-rated electric utilities in 1984 was 15.4%. FEA believes that allowed rates of return are important to investors in forming reasonable expectations regarding rates of return on common equity which comparable companies are likely to achieve.

SDG&E, staff, and FEA used comparable earnings analysis as a check on the reasonableness of the SDG&E's specific DCF results upon which they primarily rely. San Diego, which did not submit DCF testimony, relies primarily on its comparable earnings testimony for its quantitative analysis of SDG&E's cost of equity. UCAN expresses confidence in San Diego's approach.

We feel that the comparable DCF approach utilized by SDG&E, staff, and FEA may provide a useful check on the reasonableness of these parties' utility specific cost of equity analyses. We find the comparative analyses of allowed rates of returns provided by San Diego and FEA are also useful, since they provide direct insight into the return on equity expectations investors are likely to have with regard to their potential alternate utility investments in the competitive capital marketplace.

c. *Risk Premium*

The risk premium approach recognizes that there are differences in the risk and return factors for investors holding common stock as compared to bonds. The risk differential between common stocks and bonds is expressed as a premium and is added to the estimated cost of a company's long-term debt to determine the required return on common stock. An average risk premium over an extended time period is usually applied to eliminate the variances in the premium observed over time; however, there may be instances where more recently observed premiums are more appropriate in determining current investor expectations.

SDG&E estimated a long-term historical risk premium of 5.4% for the period from 1953 to 1982 which it added to a projected bond yield of 13% to arrive at a cost of equity of 18.4%. Staff estimated the premiums SDG&E's common investors have required over A and Baa rated utility bonds for ten-, five- and three-year periods between 1975 and 1984, and added these figures to its 13% debt cost estimate to find a required return on equity for the test period from 15.44 to 16.47%. FEA based its risk premium analysis on the difference between a DCF calculated return on equity and the then current long-term Treasury Bond (20 years) and the appropriate Moody's utility bond yields. The calculated expected risk premium has averaged about 4.9% relative to the Treasury bond rate and 2.9% relative to the utility bond rate for the period from 1972 to 1985. The risk premiums for the last five years (1981-1985) averaged 3.4% relative to the Treasury rate and 1.0% relative to the utility bond rate. The return on equity requirement derived from this approach ranges from 14.5 to 15.4%

FEA expresses extreme reservations about the risk premium method and cautions for many reasons against the use of long-term historic risk premium estimates based on data from a time when interest rates and bond returns were less volatile than they have been in the recent past. FEA presented its own modernized risk premium analysis in this proceeding largely because the Commission, in the last SCE general rate case (D.84-12-068), encouraged the refinement of quantitative methodologies. SDG&E also expressed reservations about the risk premium method, and noted that no party relied primarily on this quantitative technique.

We agree with FEA and SDG&E that the risk premium method must be approached with caution and, therefore, do not give much weight to the results of this approach. To the extent that we rely on risk premium analysis at all, we believe that the recent short-term risk premium data provided by FEA and staff provide the most reasonable indication of current investor expectations regarding the decreased difference in the relative riskiness of stocks and bonds.

d. *Capital Asset Pricing Model (CAPM)*

FEA provided a CAPM analysis in response to encouragement given in the last SCE general rate case decision (D.84-12-068, p. 28c). However, FEA had reservations regarding its use in this proceeding other than as a check on the reasonableness of estimates produced by other methods.

The CAPM estimates the return on common equity by adding a risk premium to the yield on risk-free securities. It is similar to the risk premium analysis discussed previously, but CAPM determines the risk premium in a two-step process which requires the analyst to employ judgment in estimating: (1) the risk-free rate, (2) the utility's beta, and (3) the market risk premium.

The approach used by FEA resulted in an estimated cost of equity of 12.5% to 14.1%. No other party used this method.

Bond Upgrade

After the parties presented their original return on equity testimony in this proceeding, Moody's Investors Service upgraded SDG&E's bond rating from A2 to Aa3. It is generally accepted in the financial community that there is less financial risk associated with companies with higher bond ratings. We shall consider the improvement in SDG&E's bond rating in our determination of a fair and reasonable return on equity.

F. *Conclusion*

[31] Reviewing the evidence in light of the three considerations, we are persuaded that:

1. Several of the key quantifiable economic factors which affect investors' expectations regarding their return on equity have declined since the time of SDG&E's 1984 test year rate case. Interest rates have steadily declined and the inflation rate has abated substantially.

2. SDG&E's financial health has improved markedly over the past two years. SDG&E's equity ratio, bond rating, internal generation of capital, and pre-tax interest coverage have increased, while its debt ratio and noncash earnings (AFUDC) as a percent of earnings have declined. This improvement is due in large measure to the significant reduction in SDG&E's specific business risks which accompanied the completion of its major construction projects, SONGS 2 & 3 and the South West Power Link, and the concomitant reduction in the need for large amounts of outside capital;

3. The quantitative financial model results which were, in our judgment, most appropriately derived show that a reasonable return on equity for SDG&E's 1986 test year ranges from 13.77% (low end of our DCF results) to 15.65% (high end of staff's comparable earnings results).

The reduction in the cost of capital and the slowdown of inflation, the decrease in the magnitude of the specific risks facing the company, and the judicious interpretation of financial models all indicate the necessity for a reduction in SDG&E's authorized return on equity.

We have taken into consideration all of the evidence relative to the key money market factors, SDG&E's own financial condition and the magnitude of the specific business risks currently facing the company, and all of the testimony regarding quantitative financial models and conclude that a rate of return on equity of 15% is just and reasonable for SDG&E during the 1986 test year rate case cycle. This return on equity produces an overall return of 12.37%.

We acknowledge that our decision to adopt a 15% rate of return on equity is a subjective one. Indeed, all of the econometric models employed by the parties involve, to varying degrees, subjective judgement and a reliance on past events which may not recur. The rates of return generated by the models are based on historical data. These numbers, such as dividend yield and the factors used to project a dividend growth rate, reflect the utility's operations at a time of market volatility and under the terms of a prior rate case decision wherein a 16.00% rate of return on equity was authorized. This high cost of capital has its own inflationary effect on the company's historic data. In addition, the risk premium calculations are comparable earnings analyses made by the parties are somewhat outdated, as the company's bond rating was recently upgraded.

TABLETABULAR OR GRAPHIC MATERIAL SET FORTH AT THIS POINT IS NOT DISPLAYABLE

XIII. *Summary of Earnings*

The result of the entire preceding discussion is illustrated in Appendix B [omitted herein] which develops the following Revenue Requirement increases:

1. Electric Department	$ 9,597,000
2. Conservation Adjustment*	(1,143,600)
3. Net	8,453,400
4. Gas Department	3,272,000
5. Conservation Adjustment*	(6,504,500)
6. Net	(3,232,500)
7. Steam Department	1,445,000

8. Total Revenue Requirement Increase (Ln. 3 + Ln. 6 + Ln. 7)	$6,665,900

*Conservation adjustments are due to:

1. Unspent conservation funds

2. Excess collection of CALPAC and CPA offset rates now rolled into base rates.

XIV. *Marginal Cost, Avoided Cost, and Incremental Energy Rates*

[32] We will continue our policy of basing revenue allocation and rate design on marginal costs, we must now consider the calculation of the marginal costs in this case. Closely related to this calculation is the associated calculation of the avoided costs and incremental energy rates used to produce prices paid to qualifying (QFs).

A. *Marginal Energy Costs*

[33] Marginal energy costs are the change in variable costs resulting from operating changes on the systems to meet a small change in load. These costs are primarily fuel and O&M costs. In this proceeding, the staff and company has essentially reached agreement on the calculation of the marginal energy costs. The only difference is that SDG&E supports inclusion of A&G costs in the marginal energy costs for certain purposes. We agree with the staff that these costs should not be included; this is consistent with our treatment of these costs in the last SCE decision.

UCAN, however, argues that a longer term view of marginal costs should be used for rate design. Acknowledging that there is yet no acceptable method for the calculation of long-run marginal cost, the UCAN witness testified that levelized future short-run costs are a proxy for long-costs. The witness also testified that use of the short-run costs will tend to understate the relative weight of the energy cost compared to the other components. The UCAN solution is to use the levelized short-run costs for a 20-year period.

While we recognize the problems UCAN cites with regard to the use of the short-run costs, we feel that UCAN's solution ventures too far in the direction of long-run costs for which we are not yet prepared. We will instead use the short-run energy cost as originally developed in Exhibit 52. This approach uses a slightly higher than predicted fuel price but results in incremental energy rates very similar to those developed with a more accurate fuel price (Exhibit 146). These marginal energy costs do not include the A&G expenses. This methodology gives a result that provides a more reasonable weighting to the marginal energy component of total marginal costs without distorting the incremental energy rates unreasonably.

B. *Marginal Generation Costs*

The company and the staff differ over the estimated carrying costs of a gas turbine. The staff used a statewide average whereas SDG&E used a company specific costs. We will adopt SDG&E's estimate of marginal generation cost as more accurate.

C. *Marginal Transmission and Distribution Costs*

There was no exception taken with the company's calculation of these costs and they will be adopted with the exception of the distribution costs which will be modified to reflect our discussion of marginal customer costs below.

D. *Marginal Customer Costs*

[34] To date, there is no consensus on the correct calculation of marginal customer costs. This proceeding reflected that lack of consensus. Different calculations were presented by the company, the staff, and UCAN.

The company included in its calculation all costs related to customer related distribution investment expenses, associated operating and maintenance expenses, customer accounts expenses, and customer services expenses. The staff accepts this basic methodology, which has as its base the “minimum distribution system” concept (customer related distribution investment).

A major assumption underlying cost theory is that the marginal cost will be the same for either a very small increase or decrease. This will occur because the cost elements are homogeneous. UCAN shows that customer costs as calculated by the company are not homogenous and that the marginal cost of adding a customer is much greater than the marginal cost of a customer leaving the system.

The economic signal that should be sent is to those customers that are on the system and that signal is the cost savings of a customer leaving the system. The signal to customers coming on to the system is properly transmitted through line extension charges, not rates.

CMA asks where customer costs as calculated by SDG&E are accounted for if they are not included in the computation of marginal customer costs. UCAN's answer and the one we adopt is that certain of these costs are more in the nature of marginal distribution costs. We will, therefore, adopt the adjustments to marginal distribution costs offered by the UCAN witness, which introduces marginal demand distribution costs 17% higher than those computed by SDG&E.

We will adopt the calculation of marginal customer costs based on the decremental customer costs analysis advanced by UCAN. The remaining controversy is whether or not the customer costs should be used in the allocation of the revenue requirement.

The following table shows our adopted marginal costs and incremental energy rates.

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E. *Avoided Cost of Capacity*

[35] The last matter to be dealt with in this area is the adoption of avoided costs for capacity payments to QFs. In the last SDG&E general rate decision, avoided cost capacity payment were developed using a shortage cost approach described as a probability of need factor (PNF). SDG&E's PNF is based on an annual system loss of load probability (LOLP) calculation.

In calculating PNFs, SDG&E excluded all forecasted supply-side capacity resources, i.e., those not existing or committed. In addition, SDG&E's proposal would not in any way limit the amount of QF capacity it would be obligated to purchase under any of the Standard Offers, nor would it adjust capacity payments if more or less than expected capacity is provided.

We view the use of a shortage cost adjustment like the PNF as appropriate and a necessary mechanism to adjust for changes in system reliability. Moreover, to preserve consistency with the long-run avoided cost methodology, (D.85-07-022) we should endorse the concept.

The Public Staff proposed that the full cost of a combustion turbine (CT), without adjustment, should be applied to those QFs who are willing to provide five years advanced notice to SDG&E of capacity termination. For prospective QFs, capacity payments would begin only in that year when the QF resource is first needed to meet the system reliability target, capacity requirement. Thus, the avoided cost of capacity would either be multiplied by one, when it was needed, or zero.

For a number of reasons this approach is unacceptable. First, as Independent Energy Producers and others point out, the one-zero approach to shortage adjustment is contrary to a number of Commission decisions, including our recent decision on long-run avoided cost calculations (D.85-07-022).

One benefit of the staff's approach is that it provides some control on the amount of capacity which can sign up. The means of this control, however, is not consistent with prior Commission decisions. Staff proposes that a system reserve margin (20 percent) be used as the standard of reliability beyond which ratepayers should not pay for additional capacity. We find that the system reliability criterion should be based on LOLP or expected unserved energy (EUE), and that system reserve margin is inadequate as an indicator of shortage value.

As explained in the section on Resource Planning, SDG&E's LOLP *result* is inconsistent with the industry standard of 1 day in 10 years. According to Kelco, an expected loss of load of 18 days in 10 years for 1986 (Reliability Data For Proposed Resource Plan) is obtained because relatively few resources supply a major proportion of total system capacity. This is a plausible hypothesis, given SDG&E's resource mix. Yet, given SDG&E's 26% reserve margin, we wonder whether the assumptions or the model (PROMOD) may be the cause of this somewhat incongruous result. If the SDG&E LOLP numbers are correct, perhaps we should be ordering SDG&E to add decentralized sources of capacity.

The Independent Power Producers argue that the staff's proposal violates a long line of Commission decisions and does not allow capacity payments to exceed 100% of the cost of a CT. With these arguments we do not disagree. However, the record in this case is inadequate to establish the shortage cost adjustment factor we think is most appropriate. It is expected that the same issues will be dealt with in detail during hearings on Phase II of the long-run avoided cost proceeding.

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Our conclusions after review of the entire record herein are as follows:

1. System "reserve margin" does not form an adequate basis for measurement of system reliability;

2. The EUE approach or the LOLP standard of one day in 10 years may provide proper measures of system reliability, yet additional evidence on the appropriate level of reliability must be provided to establish a shortage adjustment factor;

3. The value of additional capacity should be a continuum ranging from zero to more than the cost of a combustion turbine;

4. The measurement of system reliability should be the same for resource planning, cost-effectiveness evaluations, and QF payments;

5. Until a better measurement of system reliability is developed using EUE or LOLP, the value of additional QF capacity will be based on the full cost of a CT.

When shortage values and a shortage cost methodology are adopted in Phase II of the long-run avoided cost proceeding, we will expect SDG&E to come before us by advice letter filing to revise these capacity payments and use the adopted Phase II methodology, with numerical adjustments if needed, for the other standard offers.

XV. *Allocation of the Electrical Revenue Requirement*

This stage of the ratemaking process involves establishing the portion of the total revenue requirement that will be contributed by each of the classes. In this proceeding, the classes were defined in relation to rate schedules as follows:

	Rate Schedule	*Class*
1.	D	Residential (domestic)
2.	A	Commercial
3.	AD	General Demand Metered
4.	AL	Large TOU (500 kw/mth)
5.	A6	Very Large TOU (4,500 kw/mth)
6.	AG	Agriculture
7.	AY	Streetlighting

A. *Position of the Parties*

We will begin our consideration with a brief review of the position of the parties most interested in this subject.

1. *CMA*

CMA argues that customer costs should be included in the calculation of marginal costs used for revenue allocation and that the allocation should be based on 100% of the marginal costs. CMA argues that full marginal costs must be used to provide accurate price signals to all customer classes and that exclusion of the customer costs results in a revenue requirement shift from residential and commercial classes to the large users. Furthermore, CMA invokes the theory of "by-pass," "death-spiral," and uneconomic self generation to show that this revenue shift will be detrimental to the other customer classes. The CMA is, therefore, not too concerned with abrupt rate changes for the other classes.

2. *FEA*

The position of the FEA is nearly the same as that of CMA with the exception that the FEA recognizes that abrupt rate changes are not desirable and suggests a way to mitigate the impacts of full EPMC-high customer costs allocation. The FEA suggests that no class receive more than twice the system average percent change.

3. *UCAN*

It is UCAN's most basic position that any allocation process must produce equitable results. This can be interpreted to mean that no customer class should receive a disproportionate rate change. This result can be obtained by not including customer costs and/or by modifying the EPMC allocation method. UCAN provided and we adopted its method of calculating marginal customer costs in our marginal costs section of this decision. Even though it calculates marginal customer costs, UCAN argues that these costs should not be included in the allocation process because they are not truly marginal costs of the production of electricity, are not homogenous, and send price signals to the wrong customers (those off the system rather those on the system). Implicit in the UCAN position is the assumption that since we adopted their calculation of marginal customer cost with its required modification of marginal distribution costs then many of the embedded costs cited by the other parties are actually captured in the marginal distribution costs that we have adopted. This means that the effect of these customer costs will be passed on to the appropriate classes in an allocation method without adoption of marginal customer costs.

4. *PSD*

The staff, as previously discussed, advocated minimum customer costs based on embedded cost concepts. The staff included these costs in its allocation process which uses a modified EPMC method. The staff uses a modified EPMC in order to mitigate radical rate changes.

5. *SDG&E*

SDG&E originally proposed that the revenue requirement be allocated using the full EPMC method, not including customer costs, because this was the method used in the last SDG&E general rate case decision. During cross-examination, the witness for the company indicated that the company would really prefer that customer costs be included. The company realizes that inclusion of customer costs as it calculates them would require some modification of the full EPMC allocation process.

B. *Discussion*

Although it is apparent that each of the parties has presented an allocation methodology that benefits its own special interest, several valid points were made. It is now appropriate to give our general overall view on the use of marginal costs and then to develop an allocation method. For the past several years, we have consistently chosen marginal costs as opposed to embedded costs as the basis for revenue allocation and rate design. No party in this proceeding made a serious attempt to have us change this policy and we do not intend to do so at this time.

The main problem of using marginal costs in the allocation process is to reconcile the revenues at marginal costs and the actual revenue requirement. In order to make this reconciliation, we view that the marginal costs in an hierarchical fashion as follows:

1. Marginal Energy Costs

2. Marginal Demand Costs at the Generation Level

3. Marginal Demand Costs at Transmission Level

4. Marginal Demand Costs at Distribution Level

5. Marginal Customer Costs

We believe that application of the marginal costs in this order produces the most accurate signal to all consumers of the costs and consequences of their consumption decisions which in turn promotes economic efficiency. It is this hierarchy which represents to us the proper ordering of the relative importance of the various costs that are incurred.

In certain proceedings in the past, we have been able to reconcile the revenue requirement using only marginal energy costs and marginal demand costs at the generation level. We have so far not included marginal customer costs in the allocation process. In this proceeding, the marginal costs down through the marginal demand costs at the distribution level closely approximates the revenue requirement.

[36] We have agreed with and adopted UCAN's calculation of marginal customer costs. We do not, however, agree with UCAN that it is neither necessary nor desirable to include marginal customer cost in the allocation process.

The Commission is interested to have customer charges included in marginal costs for revenue allocation purposes. We feel, however, that a more fully developed record is needed if appropriate customer charges are to be fully allocated. This is consistent with our desire to as much as possible provide accurate and appropriate price signals to each customer and customer class. Equity is a major policy criterion in this regard.

Staff in this proceeding presented a case for incremental customer charges based on the addition of customers and a minimum distribution system. UCAN argued for decremental customer charges based on the costs of customers going off the utility system. UCAN also argued that marginal customer charges should produce a symmetrical effect; the costs of customers going off the system should be approximately equal to the cost of customers going on the system. It is not refuted that Staff's incremental costs were significantly greater than UCAN's decremental costs, nor is it contested that there should be in theory some symmetry between incremental and decremental costs. We have chosen to use UCAN's result at this time not because decremental costs are thought to be superior, but because the result is more moderate and the staff's approach would create major changes in our current revenue allocation.

A major problem in the area of revenue allocation is that the incremental costs of adding new customers (hook-up costs, distribution costs, and demand costs) are substantial and cannot be easily allocated to new customers.

A second problem is with decremental customer costs resulting from customers going off the system. If the decrease in demand caused by customers going off the system is compensated for by increasing demand from new customers, then the only decremental cost is for unhooking customers. Here, however, the reduced demand cost or bypass cost is picked up by new customers coming on the system but allocated to all customers in the class. Therefore, the UCAN approach may not fairly represent decremental customer costs, because a large part of these costs are actually allocated to other customers.

In short, the Commission sees problems with appropriately allocating marginal customer costs, however they may be defined. Nevertheless, we seek to embrace approaches to quantification and allocation of marginal customer costs in the future which more equitably and accurately provide correct price signals to customers to the extent this can be accomplished.

In this decision, we will exclude marginal customer costs from the allocation process, because it is difficult to avoid sending inaccurate price signals to the wrong customers using the approaches presented in this case.

With this issue resolved, and with the marginal cost revenue approaching the revenue requirement, the next issue is whether or not the full application of marginal costs needs to be modified. Several parties recognize the need to modify the EPMC method in order to mitigate abrupt rate changes. In SDG&E's last general rate case, we were able to use 100% of the EPMC. In this proceeding, several parties suggested using various percentages of the marginal costs and the system average rate change. The general theory is that no customer class rate change should vary too much from the system average rate change. Most of the parties in formulating their recommendations assumed a fairly large rate increase. Our adopted revenue requirement produces a significant rate decrease with a revenue requirement that approaches the marginal costs revenue. Application of the marginal cost as adopted to the revenue requirement produces equitable results without the need to modify the full EPMC methodology.

[37] We will, however, continue the exception of the streetlighting class. It is apparent from a review of the marginal costs that this class is paying rates that are somewhat high. In the last general rate case, we provided that this class would not receive an increase until its rates were more in line with its marginal costs. We will continue this policy by not imposing any increases on this class and by applying the system average rate decreases to its revenue requirement until our staff informs us that the relationship of its revenue requirement and its marginal cost revenue approximates that relationship of the other classes.

This decision authorizes a $12,017,000 (1.8%) revenue increase which is offset with unspent conservation funds. This increase in the revenue requirement does not result in an increase in rates because the sales have increased by an even greater amount (7.5%). The combined effect of the sales increase and the small revenue increase is a net reduction in rates faced by consumers. The total effect of the “offset” decreases (-5.3%), sales increase (7.5%), and the general rate increase (1.8%) is an overall net decrease (-8.38%).

In order to allocate total revenues, this decision recognizes and implements the effects of our decisions issued in A.85-06-064 (ECAC, AER, ERAM) and A.84-07-027

(ECAC).

The table below shows the results of our adopted allocation:

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The last issue requiring resolution in this area is the method for allocating revenue requirement changes that will take place before the next general rate case.

We have seen how the calculation of marginal costs can have a major effect on the revenue allocation and how marginal costs can change widely in a short period of time. It is easily foreseeable that we could have a *major* revenue change which when allocated with out-of-date marginal costs could have a significant detrimental effect on a particular customer class.

[38] The allocation of any revenue changes on an equal percentage (SAPC) basis has the advantage of maintaining the current relationships among the customer classes until we have the opportunity to review in a general rate case:

1. Updated Marginal Costs

2. The desirability of changing the adopted marginal cost levels

3. The magnitude of revenue changes

4. The effects different methods might have on the various customer classes.

We will, therefore, adopt the SAPC method for allocating revenue changes until the next general rate case with the exception of the streetlighting class as discussed above. The percentage relationships among energy and demand charges established in this decision will also be maintained in offset cases.

XVI. *Electrical Rate Design*

With the class revenue requirements and class average rates adopted, we can now turn our attention to specific rate design issues. Before getting involved in the details of particular rates, we find it appropriate to comment on some general themes contained in this decision which will be the foundation of our decisions on particular issues.

[39] Our first guiding theme is perhaps best captured in the following excerpt from the CMA brief:

b. Major changes in the current structure of the AL-TOU and A6-TOU rate schedules are not justified at present. Any reformulation of these rate structures should proceed from a cooperative effort among customers, SDG&E, and the Commission; however several changes are in order for SDG&E's standby tariffs.

Although we would apply this sentiment in a more general fashion to all rate schedules, we do agree that at this time a degree of rate structure stability is desirable. We also intend to emphasize the concept of cooperation in rate design. This is one of the reasons that we have supported the SDG&E request to implement a demand side management program.

As an example, it is apparent that the TOU rates have not gained a broad acceptance among the customers, although we still believe that they provide correct price signals. It is our suspicion that these rates have been designed from a theoretical perspective rather than from the perspective of accomplishing the same goals with rates that are more acceptable to both the company and the customers.

In this proceeding, we still have the large industrial customers complaining of their revenue requirement burden rather than recognizing that the classes that have TOU rates available have the option to lower their rates simply by changing their usage patterns. Although these major industrial customers may state that they are faced with the choice of remaining in California or going elsewhere, we believe that their choice is more appropriately viewed as being between locating outside California and shifting their usage to different time periods.

We want SDG&E to integrate load management and rate design to a much greater extent than it has in the past. It is our hope that by giving SDG&E the opportunity to develop its DSM program, it will be able to redesign rate structures that will continue to provide the correct economic price signals and at the same time have a more broad base of support among the affected customer classes. We intend to make what we consider to be minor adjustments rather than major changes until this process is given an adequate opportunity to succeed.

A. *Residential*

With the foregoing preliminary comments in mind, we can now look at the issues affecting residential rate design. The first such issue is the idea of a customer charge.

1. *Customer Charge*

[40] The most radical change proposed for the residential class is the suggestion by the PSD that a customer charge be imposed. We have considered this issue several times in the past. In fact, we eliminated the customer charge for SDG&E in its last general rate case proceeding. The staff now proposes that it be reinstituted in order to cover certain specific embedded costs. The proposal is opposed by UCAN and not strongly supported by any other party.

The staff seems to accept but not acknowledge the effect of the baseline legislation (Code Section 739). We have decided that the baseline rate level should be computed by incorporating customer charges or minimum bill revenues. To do otherwise would totally negate the requirement that “baseline” can be no higher than 85% of the system average rate. With this requirement, it really makes no sense to segregate out a special “flat charge” which has historically caused substantial customer confusion and anger. The staff evidently failed to make a study of customer support for such a charge. In the absence of compelling need, we will not reinstitute this customer charge and will retain the $5 minimum bill.

2. *Baseline Allowances and Level*

[41] The staff has analyzed SDG&E's residential bills and determined that several schedules within the residential class exceed the maximum allowed baseline allowance. The staff recommends that these amounts be revised gradually between now and the time of the next general rate case. SDG&E counters that the baseline amounts have only been in effect since 1984 and that there has not been sufficient change in usage patterns to warrant a change in baseline levels at this time. SDG&E also requests that any changes ordered be implemented gradually.

We agree with the staff. If the allowances were either implemented incorrectly or have since gotten out of line then they should be corrected before the divergence is even greater and preferably at a time that we are implementing a rate decrease rather than an increase. We will adopt the mechanism proposed by the staff to revise the baseline allowance levels over the next three years starting in May of 1986.

Another similar issue is the staff proposal that the allowances for master metered customers that do not submeter be reduced initially by setting them at 75% of the corresponding individual baseline allowance, then further reducing them to 70% later. Again, with the prospect of a rate decrease, we will adopt the staff recommendation for the initial change but not allow any further change until the next general rate case.

The final allowance issue concerns the treatment of electric water heating customers. During the implementation of the baseline legislation, customers that had gas space heating but electric water heating were grouped with the “all-electric” customers and thereby received a large baseline allowance. The staff recommends that we not take away any of this allowance for present customers, but that the excess allowance be reduced with a change of customers at those addresses, in effect “grandfathering” the present customers. We feel that staff's approach may give rise to impermissible discrimination between similarly situated customers and believe it is better to reduce the excess allowances effective with the spring seasonal baseline changeover (May 1, 1986).

3. *Submetering Discount*

[42] In this proceeding, SDG&E has computed the submetering discount by applying certain escalation factors to a cost of service study performed in 1979 to arrive at a flat submetering discount. SDG&E then adjusts this discount downward by a diversity factor which it developed in a study of one mobilehome park consisting of about 370 spaces. This factor would offset the projected inflation factors for the period 1986-1987. The staff opposes any change in the submetering discount until a complete cost of service study is performed by both the company and the mobilehome parks.

The Western Mobilehome Association (WMA) agrees with the basic escalation study performed by SDG&E, but disagrees with the diversity factor adjustment. The WMA argues that “common area” usage would offset the diversity adjustment. WMA's second argument is that the diversity study was not sufficiently rigorous to produce a universal adjustment factor.

We will adopt the escalation in the discount as computed by SDG&E without adjustment. We agree with the WMA that the one sample is not sufficient to adopt the diversity factor. However, now that SDG&E has shown that such a factor probably exists, we are very interested in seeing the results of a better study in the next general rate case.

There was not an adequate showing made to justify changing the other submetering discounts. The staff recommendation to leave them at their present level is adopted.

4. *Daily Allowance Billing*

In this proceeding, the staff recommended that the baseline allowance be calculated on a daily basis. Since the time of staff's proposal, we have accepted an advice letter filing implementing the staff proposal effective October 1, 1985.

5. *Residential Common Usage*

We will adopt the request by both the staff and the company that residential common usage be governed by residential tariffs.

6. *Residential TOU*

[43] The following quote from the company brief illustrates not only the staff recommendation but also the company's attitude on Commission imposed experiments.

The Commission should accept Staff's proposals for these experimental tariffs since, in SDG&E's opinion, these tariffs were created at the Staff's suggestion and they would best know the purposes of these experimental tariffs.

It is clear that the company has had no involvement in this rate. It is also clear that the customers themselves were not consulted. In such circumstances, we fear that this rate experiment will be doomed to failure. However, since this program is entirely voluntary and since PG&E is involved with a much more comprehensive experiment in this area, we can adopt the staff recommendation.

7. *Service Establishment Charge*

The following table illustrates the current SDG&E proposed and staff recommended charges for the establishment of service.

		Current Rates	*SDG&E Proposal*	*Staff Proposal*	*Adopted*
1.	Change of account without meter read	$ 0.00	$ 7.50	$ 5.00	$ 5.00
2.	Turn-on or change of account with meter read	15.00	15.00	15.00	15.00
3.	Turn-on evenings or within 4 hours	30.00	30.00	100.00	30.00
4.	Appointment for Turn-ons	Not Available	60.00	60.00	60.00
5.	Turn-on Sundays or Holidays	Not Available	60.00	100.00	60.00

Although the charges recommended by the staff are based on fully loaded costs, we believe that the schedule proposed by SDG&E, which also takes into consideration administrative ease and simplicity, is more reasonable and we will adopt it. The one exception is the charge for a change of account made without a meter read. The company charge of $7.50 was opposed by both the staff and UCAN. The staff suggested rate of $5.00 is more reasonable and will be adopted.

8. *Collection Charge*

The staff and the company have agreed on a collection charge that will be assessed whenever field visits have to be made to effect collection of delinquent accounts. The agreed upon program will be adopted.

B. *Non-TOU Commercial, Industrial and Agricultural*

Schedule A - General Service

Schedule AD - General Service (Demand Metered)

Schedule PA - Agricultural

SDG&E's proposal for these schedules can be generally characterized as substantially increasing customer and demand charges with minor changes in the commodity components. The staff recommends smaller increases in the customer and demand charges.

[44] Both the staff and company recommendations were made in contemplation of a fairly significant rate increase. In reality, we are implementing a substantial rate decrease. We can, therefore, increase the proportion of the fixed charges in the total charges and maintain a degree of rate stability by applying the total decrease to the commodity charges. The customer and demand charges will remain at the present levels except as noted below.

SDG&E recommends adoption of a good load factor discount for Schedule AD and modification of the voltage discount for both Schedules A and AD. Staff recommends more extensive modification of the voltage discount. In order to foster rate stability, we will not adopt either recommendation.

Other suggestions that were fairly noncontroversial and that will be adopted are that the PA-TOU schedule be opened to all of the appropriate customers, the staff's suggested PA-TOU metering charge, the flat customer charge advocated by the staff for the PA schedules, opening Schedule A-6 TOU as an option for all customers with demands exceeding 500 kW, and eliminating Schedules AL-CG and A-6CG as recommended by staff.

C. *Industrial TOU (AL-TOU - A6-TOU)*

This was the most complex area of rate design in this proceeding. The subjects of major recommendations were:

1. Demand charges levels

2. Customer charges levels

3. Commodity rate differentials by time period

4. Standby rates levels

5. Voltage adjustments

6. Good load factor adjustments

7. Interruptible rate discounts

8. Capacity factor adjustments for standby customers

Parties presenting evidence on these matters and making recommendations were:

1. SDG&E

2. PSD

3. CMA

4. FEA

5. ACWA

6. Mineral Products Industry Coalition

It is easy to see that the number of subjects, the number of active parties, and the lack of consensus, make this subject rather unwieldy. It is appropriate to recall at this time our general theme that additional rate design studies must be conducted and integrated with load management studies. These studies must bring the affected customers into the process in a meaningful way. The final prong of this multi-part policy is that at this time we will attempt to maintain some rate structure stability by only making major changes where absolutely necessary, and by using the revenue decrease to effect changes deemed desirable. Viewed with these goals in mind, the various recommendations can be divided into the following three groups:

1. those to be adopted in this decision.

2. those that are considered to be good ideas but that should be considered further and implemented at a later date.

3. those that will not be adopted or endorsed.

1. *Summary of the Positions of the Parties*

SDG&E

The key thrust of the company position is to prevent loss of load. The company has, therefore, proposed an increase in the levels of demand charges, customer charges and standby rates together with a rather flat commodity charge. These proposals were made in contemplation of a revenue increase. SDG&E also opposed demand charge waivers and proposed voltage discounts and good load factor discounts in an apparent attempt to prevent the loss of load of very large industrial customers to cogeneration or self generation.

PSD

The staff presented a very ambitious program for restructuring the TOU rates to bring them more in line with marginal cost principles and of SDG&E's load patterns. The staff proposes much greater commodity rate differentials and somewhat higher demand charges. The staff also proposed the creation of a new nontime differentiated demand charge and the elimination of most of the winter demand charge. Finally, the staff offered a much wider choice of interruptible rate design options.

CMA

CMA seems to believe that no one knows if, how, when, or in what form TOU rates are effective. Therefore, it recommends that we do not do too much to change the status quo, but rather that we should continue to study and experiment on a small scale with the TOU program. Most of CMA's recommendations are, therefore, negative in nature and oppose most of the changes advocated by the company and the staff. CMA does recommend the adoption of certain experimental and voluntary new rates.

FEA

The primary recommendation of FEA is that a higher proportion of the total revenue collected from this class should be made up of demand charges as opposed to commodity charges. FEA essentially agrees with the recommendation of SDG&E on this matter.

Mineral Products Association

This association opposes the increased demand charges, suggesting instead that the commodity charges be increased in order to spread the demand costs to the class in a more even manner.

ACWA

It is ACWA's contention that the TOU schedules currently applicable to “water pumpers” should be modified on an experimental basis by shortening the on-peak time period.

2. *Discussion*

Because so much of our decision on TOU rate relies on marginal costs, we will develop a table from our previously adopted table of marginal costs below.

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[45] >With these figures in mind, we agree with the staff that the commodity rates must be brought closer in line with the marginal costs. We also agree that more of the revenue should be recovered in the demand charges than is now the case. As the table shows, the demand costs clearly vary by time period. The staff by introducing its nontime differentiated demand charge that would be additive to the on-peak demand charge has attempted to add a demand charge that would be applicable in the mid-peak and off-peak periods. While the staff has shown a reasonable basis for the adoption of the new demand charge, it has such a lack of support at the recommended level that we feel that this concept must be studied further in cooperation with the company and customers before we will consider it further.

The concept behind the staff proposal (time differentiated demand charges) is clearly appropriate, and we will adopt a mid-peak demand charge of $.50/kw/mth as a first step toward a more realistic level. The implementation of this mid-peak demand charge will be delayed until May 1 to allow SDG&E time to reprogram its meters to capture and second mid-peak demand levels.

The best solution to the varying recommendations in this proceeding is to hold the customer and demand charges constant for the time being (except as noted above) and to apply the rate decrease to the commodity rates in such a way as to have the commodity rate differentials approach the staff recommended ratios of 2.8: 1.8: 1. This will produce a rate structure that recovers about 15.5% of the revenue in the demand charges as compared to 11% at present.

3. *Standby Rates*

[46] Standby service is provided to customers who normally receive all or part of their electrical energy from sources other than the utility but rely on the utility for backup service. This service is provided under Schedules S, SQF, and SQF-I. In this proceeding, the staff has proposed a major rationalization of the standby rate structure. The staff calculates standby charges using avoided cost principles and provides major incentives (demand charge waivers) for the standby customers to conduct their operations in an efficient manner. We cannot tell with certainty whether the staff proposal will result in an increase or decrease of the standby charges. We will adopt the staff recommendation as a total package.

Both CMA and the QFs oppose the staff's proposed increase in standby charges to $5/kw/mth. Their argument is based almost entirely on a previous decision that contained a finding that the standby charges for QFs could reasonably be increased in the future based on the increase in capacity costs. The intervenors show that the capacity costs have increased in the range of 5-25% and argue that, therefore, the standby charge should increase from $1 to no more than $1.05-$1.30/kw/mth.

The staff shows that circumstances have drastically changed since our previous D.82-01-103 in that San Diego now has excess capacity and that QFs no longer need to be encouraged by below cost rates. The staff also shows that its proposal is a restructuring of rates applicable to the standby customers and not simply an increase. The charge could result in an increase or a decrease to standby customers depending on the cost that they impose on the utility system. The staff shows that the more efficiently the standby customer conducts its operations then the less costs it imposes on the utility. The staff program recognizes this concept by providing a waiver of demand charges and a reduction in standby charges whenever the standby customer exceeds capacity factor standards which are based on the utility's avoided costs. Staff also shows that since standby customers are not distinguished on the basis of their QF status, the charges assessed QF and non-QF standby customers should be the same.

The SDG&E proposal for a similar increase in the standby charges was not accompanied by any mechanism for waiver of demand charges or reduction of the standby charges based on the standby customers capacity factors. The SDG&E proposal, by not recognizing the offsetting effects, has the appearance of being a mechanism to enhance revenues or to discourage cogeneration.

4. *Interruptible Rates*

The staff's interruptible rate recommendations were supported by CMA and were not otherwise seriously contested. Both SDG&E's and the staff's proposed interruptible proposals will be adopted as recommended by CMA. The proposals were based on avoided cost principles and the rates are optional.

5. *Experimental Proposals*

During the course of these proceedings, three parties made experimental proposals. First, CMA recommended that a TOU optional rate proposed by SDG&E in late 1984 be adopted. This is consistent with our overall policy of encouraging further study of TOU rates in cooperation with the staff and affected customers. This proposal has been under discussion through the advice letter process, and we expect this process to result soon in an adopted tariff acceptable to all parties.

Second, ACWA proposed that the agricultural TOU schedule be modified to reduce the length of the on-peak periods to more closely track the system “super-peak.” This should make the TOU rates more attractive to the “water pumping” class of customers. ACWA proposed that this experimental rate be limited to a small fraction of the affected customers. ACWA presented its proposal in a conceptual form in its original exhibits, and the proposal was further developed during cross-examination of ACWA and the staff, and in ACWA's opening brief. ACWA's revised proposal as stated in its opening brief was uncontroversial and will be adopted, effective May 1, 1986, with adjustments reflecting the rates adopted in this decision for Schedules AL-TOU and A-6 TOU.

The staff also proposed new optional TOU rates for small agricultural and small commercial customers, with the goal of keeping TOU rates affordable for these customers. Because this need can be served by maintaining the customer charge for Schedule AL-TOU and adopting ACWA's proposed tariff at $20 per month, and because we are approving SDG&E's DSM proposals, we will defer adoption of the new rates proposed by the staff.

In discussing the experimental TOU rates, the question of when the results of the company's studies (DSM) and the various experiments can be implemented is raised. In encouraging the company to embark upon load management-rate design studies, it is incumbent on us to provide a forum for the implementation of the results of these studies before the next general rate case three years hence. We will expect the company to make advice letter filings for new or improved rates in the interim period, and to implement effectively the rate options that are created by this decision and those that already exist. If these rates are controversial, they can be set for hearings at an appropriate time.

6. *Conclusion*

In our discussion of TOU rates we have resolved the following:

1. Customer and demand charges will be held constant.

2. Time differentiated demand charges are to be studied further and a minor phasing-in will be implemented.

3. Good load factor discounts will not be adopted. Voltage discounts will not be modified.

4. PSD and company proposals for interruptible rates will be adopted.

5. Standby charges will be adopted with PSD's proposed waiver of demand charges and with standby charge reductions based on capacity factors.

6. The ACWA limited experiment on a reduction of the length of the on-peak period for water pumpers will be adopted.

7. The rate decrease will be used to implement the above with any residual decrease being applied to the commodity rates.

D. *Streetlighting*

Both the staff and CAL-SLA agree that the streetlighting rates should be set in an unbundled fashion. The controversy is in the first step of the “unbundling” process where a facilities valuation is required. The staff uses the “replacement cost new less depreciation” method whereas the company uses the “original cost less depreciation”. The staff method results in a higher proportion of facilities charges.

The staff's recommendation is based on the fact that the sale of several properties of utilities has been based on the “replacement cost new” method. We believe that the “replacement cost new” is a closer approximation of the marginal facilities costs.

CAL-SLA argues that there is a 70-year history of having rates based on the original cost less depreciation method of valuation.

We agree with the staff that the “replacement cost new less depreciation” method should be used for rate design. It is true that the “original cost less depreciation” method of valuation is used to develop the revenue requirement, but the revenue allocation and rate design are based on marginal costs. The staff's method of designing rates more closely approximates a marginal cost method of developing rates within the constraints of the revenue requirement previously adopted for this case. We adopt the staff's method of calculating rates for these schedules, modified so that the maximum annual upward realignment within the lighting class will offset the decrease in class revenue granted in this decision (i.e., no increase in any single rate in this decision).

E. *Adopted Rate Design*

The following table illustrates our resolution of the major rate design issues.

TABLETABULAR OR GRAPHIC MATERIAL SET FORTH AT THIS POINT IS NOT DISPLAYABLE

XVII. *Gas and Steam Rates*

Gas and Steam rate design were not significant issues in this proceeding. This decision develops a new gas margin which will be carried over to our decision on SDG&E's fall

CAM proceeding. That decision will implement new gas rates to recover the adopted revenue requirement. There are some general rate design questions that we resolve herein.

The general issues relate to (1) submetering discounts, (2) collection charges, and (3) service establishment charges. All three of these issues were discussed in the portion of this decision on electric rate design. The issues are the same; our discussion will not be repeated. The same results are adopted.

Steam Rates

[47] SDG&E has proposed that the steam rates be increased by reflecting the full cost of steam production. The staff concurs with this recommendation. Both SDG&E and the staff recommend that this schedule be closed to new customers and phased out. We will adopt the company request to increase steam rates by 100% and direct the company to assist the present customers in making different arrangements for their end use needs. Once the schedules are completely closed out, any remaining balance in the steam balancing account will be transferred to the appropriate electric balancing account.

XVIII. *Affiliates and Subsidiaries*

There are two issues regarding this subject in this case. The first is that SDG&E has requested authority to form a holding company in order to diversify into nonutility but related operations. A decision in that case could have an effect on the capital structure of SDG&E and its revenue requirement. Our decision in that proceeding will resolve any and all ratemaking issues as they might apply to SDG&E.

The second issue concerns the relationship of SDG&E with an affiliate company that was previously a subsidiary. The portion of the record in this proceeding which deals with this relationship has been incorporated into the record of SDG&E's fall ECAC proceeding (A.85-06-064). The resolution of the issues raised in both proceedings will take place in our decision on the ECAC matter.

XVIX. *Resource Planning*

[iv] SDG&E's management has determined that the company should no longer view itself as the potential individual owner/operator of new large central station power plants. Instead, the company is making substantial efforts to identify opportunities for purchasing power from out of state, and for potential investment in existing power plant projects or participation in future power plants. The company expects its future capacity needs to be met by a combination of purchases and investment, rather than the construction of large, long lead-time power plant projects.

To accomplish its resource plan objectives, SDG&E has conducted studies of future energy sources to determine the availability for purchases and investment. In addition, the company is placing a strong emphasis on future transmission resources which will be necessary to provide access to the potential sources of power.

The object of resource planning is to provide energy services in a reliable and cost-effective manner. Of necessity, this requires a methodology to evaluate risk, equity, and efficiency with respect to demand and supply-side resource options. We view the utility as responsible for comprehensive least-cost resource planning, and thus, it should provide adequate information and analysis to justify its resource plan.

Resource plans are used to determine short- and long-run marginal costs, which in turn affect rate design, QF pricing, and conservation and load management cost-effectiveness. In rate design a near-term resource plan is used to determine which plants will be on line during the test year. Marginal energy costs are developed for each hour of the year by determining which plant will be brought on line at each load level. The hourly marginal costs are averaged by summer and winter on-peak, off-peak, and mid-peak costing periods. These averages are then used in rate design to establish the differentials for the time-of-use rates. An annual average marginal cost is determined for each customer group and the results applied in determining the revenue requirements for each group in direct proportion with their respective average marginal costs. QF capacity prices and energy prices are also affected by the resource plan. Therefore, the better and more comprehensive the planning process is, the more useful the results will be for the above purposes. Hence, the staff recommends and we direct that future submissions of the utility's resource plans to the Commission should include:

A detailed description of the resource planning process, including the analysis steps, and the levels of review and decision making. They should also present alternative resource mixes considered during the process, and the reasons for these being discarded, including comparative reliability and economics with the adopted one.

We are primarily concerned about future levels of service reliability in SDG&E's territory and the cost-effectiveness of resource opinions it seeks to employ.

A. *Reliability*

With respect to the reliability of the SDG&E system, we are particularly concerned about the apparent confusion reflected in the various showings in this proceeding. In general, we agree with Public Staff that the resource plan submitted by SDG&E is adequate to maintain a level of reliability in its service territory which is sufficient to meet customer service needs. Reserve margins expected in 1986, 1987, and 1988 are forecasted to be 25.9%, 24.5%, and 22.2%.

In this case, SDG&E computed a Probability of Need Factor (PNF) which was to be used to modify the value of added QF capacity, respectively. The basis for SDG&E's probability of need factors, loss of load probability (LOLP), seem quite inconsistent with the standard of one day in 10 years. The question is, why has SDG&E reduced the probability of need factor (PNF) to less than one, when the LOLP standard of one day in 10 years is exceeded by up to 23 days per year? Moreover, the PNF provided by SDG&E does not correlate with reserve margin or LOLP. This is a signal to the Commission that SDG&E needs more cost-effective resource planning and more effective reliability criterion.

We will require that SDG&E reevaluate their PNF before the next rate case and establish a reliability factor to be used for resource planning analysis, avoided cost capacity adjustments, and cost effectiveness evaluations. This may be accomplished in the long-run worded cost proceeding. The PNF should be based on LOLP or expected unreserved energy (EUE).

The staff also recommends that future submissions of the utility's resource plans to the Commission include:

Reliability considerations: criteria used in obtaining minimum planning reserve margin, focusing on:

1. Loss of Load Probability (LOLP) power flow analysis for single and interconnected system.

2. Maintenance requirements.

3. Forced outage rates for generation and transmission.

4. Plant retirements and “cold storage.”

5. Perform customer cost-benefit analysis for different levels of utility reliability.

We adopt these staff recommendations with one exception; both LOLP and affected unserved energy should be analyzed and used for situations where LOLP is relevant. We wish to emphasize that we completely endorse adding the concept of “value of reliability” to the resource planning process.

In our earlier discussion regarding the capacity payments to be paid to cogenerators, we indicated that there appears to be no standard method for computing LOLP nor indices of EUE among the utilities. Therefore, we have no confidence that the uses served by the resource plan are applied evenly throughout the state. We realize that heretofore there has been no agreed upon method to obtain the kind of information that we seek, but it appears that substantial progress is being made.

B. *Cost-Effectiveness*

The Commission is very concerned about ensuring that resource additions, whether they be conservation, load management, QF's, utility plants, or power purchases, be cost effective for present and future ratepayers. This, of course, requires a methodology to define the most economically appropriate mix of resources and that various resources be placed on a comparable basis so that choices among resources can be judged. For supply-side resources, the methodology adopted in D.85-07-022 for long-run avoided cost calculations may be a suitable standard.

It is hoped that the Commission and the states' utilities can agree on a consistent standard practice for cost-benefit analysis for both supply and demand-side resources in the near future. We are particularly concerned to provide a standard approach to cost-effectiveness in light of the need to compare all energy options in an increasingly competitive energy market place, and move toward more effective least-cost energy planning.

The Public Staff recommends that future resource plan submissions by SDG&E include greater detail on how alternative resource mixes are analyzed for reliability and cost-effectiveness. We support staff's recommendation and emphasize the need to provide credible cost-effectiveness analysis in resource planning situations.

We believe that by adding cost-effectiveness studies to resource plans the ability of the utility to conform its supply to the real demand will improve substantially. We believe that the historical method of resource planning has been to simply project demand and then try to find the least cost method of supplying that demand. This process leaves out of the equation entirely the fact that capacity (particularly excess capacity) and energy have both a value and a cost. It is this relationship that we want to understand in much more detail than has been supplied to date.

With regard to computer models used for cost-effectiveness evaluations, we recognize Ernst & Whinney's recommendation that other cost-simulation models be used instead of PROMOD to increase computational efficiency and the accuracy of results. In order to analyze alternative resource mixes using least-cost criterion and increase computational efficiency, Ernst & Whinney and ACWA suggest that SDG&E use the AGEAS model developed by EPRI. We also note, however, that Commission D.83-12-068 directs the state's utilities to work toward agreement on a statewide model for use in the calculation of avoided-costs in the OIR-2 proceeding. We think that consistency with that directive is also important and should be a part of SDG&E's choice of a computer model in cost effectiveness calculations.

We wish to emphasize that after a common cost-effectiveness methodology and common computer models are agreed upon, the critical focus can then be more sharply directed upon the assumptions used in the analysis. The assumptions upon which the cost-effectiveness analysis is based should, of course, be a primary focus of staff and utility review.

C. *SDG&E's Current Situation*

SDG&E has embarked on a strategy to obtain substantial amounts of out-of-state power and power from QFs. Currently, it seems that SDG&E has sufficient capacity but would benefit from purchases of economy energy. Moreover, SDG&E may have overcommitted to firm power purchases during the 1986-88 period, but thereafter it may be able to obtain significant additional economy energy. We suggest that SDG&E work vigorously to obtain additional low cost economy energy purchases, particularly over the SWPL.

We also suggest that SDG&E work to clarify the apparent vagueness and imprecision in their resource planning process, particularly by defining the relative costs of "retired," current, and future resources based on each units contribution to production costs and system reliability. SDG&E's resource plan exhibit for the instant case consisted of three pages of general narrative and four pages of tables defining megawatt and gigawatt-hour additions expected up to the year 2004. Resource costs and terms like "least-cost planning" were never used or addressed. For these reasons, we find the SDG&E showing on their resource plan inadequate.

XX. *Southwest Power Link*

[48] In Decision 84-12-065, the 1984 ECAC reasonableness review, the Commission directed SDG&E and staff to address the status of SWPL in the current rate case, specifically "to determine whether there is reasonable use being made of the SWPL." This was a result of the Commission's concern that "the record in that proceeding was inadequate to determine the reasonableness of the purported savings from the SWPL."

SDG&E claims that reasonable use has been and will continue to be made of the SWPL. It has submitted testimony which describes the past and projected amounts of power produced under firm capacity and economy energy contracts. It is clear from the record that the SWPL is being heavily used. SDG&E claims that Commission inquiries into the proper resource mix and the reasonableness of power costs are matters to be addressed in the ECAC proceeding.

The Public Staff asserts that SDG&E's resource plan is consistent with the use of the SWPL for the period 1985-88, but also recommends that the availability of commensurable economy energy from the southwest be ascertained before the line is uprated with the installation of series compensation. Staff witness Monson recommends that the upgrade be disallowed because of questionable cost-effectiveness. PSD witness Paula affirms this conclusion. Staff concludes that the SWPL upgrade is an uneconomic addition. Thus, Staff defends the use of the SWPL line itself without analyzing the economics of its use, and argues against the SWPL upgrade because it is not cost-effective.

UCAN contends that the purported savings from the SWPL do not exist. UCAN believes and we agree that its showing is the only evidence that directly addresses the issue of SWPL's economic savings, which the Commission directed the applicant and staff to analyze.

During the 1986-88 period, based on SDG&E's power purchase forecast SDG&E ratepayers will pay over $90 million more for SWPL energy than they would for energy priced at avoided costs. We observe that SDG&E is storing units that can generate energy for less than 6 cents/Kwh, but at the same time it is purchasing energy over the SWPL for 10 cents/Kwh in 1986 and more than 11.1 cents in 1987. In addition, by loading the SWPL with expensive firm purchases, little room is left for inexpensive economy purchases. Based on our review of the record we find that the purported savings from the SWPL are indeed nonexistent. In fact, the excess costs of SWPL, which ratepayers incur without commensurate benefits, present a prima facie case of unreasonableness.

In the 1986-88 period, the SWPL will result in substantial rate increases to SDG&E ratepayers without corresponding benefits. UCAN's witness provides a comparison of the cost and value of power delivered over SWPL. Table 2 shows the total average costs for power purchased over SWPL will be 7.92 cent/Kwh in 1986, 7.90 cents/Kwh in 1987, and 7.26 cents/Kwh in 1988.

Comparison of Cost and Value of Energy Delivered Over SWPL

	1986	*1987*	*1988*
Capacity delivered (MW)	499	567	461
Energy delivered (GWh)	3,798.1	4,084.4	4,298.1
Cost of energy ($ million)	261.3	284.8	276.9
Existing line rev. req.	37.3	34.5	31.9
Series capacitors	2.1	3.3	3.2
Total line rev. req.	39.4	37.8	35.1
Total SWPL cost ($ million)	300.7	322.6	312
Total cost (cents/kwh)	7.92	7.90	7.26
Avoided energy cost (cents/kWh)	5.68	5.92	6.36
Avoided energy value ($ million)	215.7	241.8	273.4
Avoided capacity cost ($/kW-yr.)	70.00	74.90	80.14
Avoided capacity value ($ million)	34.9	42.5	36.9

Total SWPL value ($ million)	250.6	284.3	310.3
Total value (cents/kWh)	6.60	6.96	7.22
Cost exceeds value ($ million)	50.1	42.	1.7
Cost exceeds value (cents/kWh)	1.32	.94	.04

This decline is caused by the expiration in 1987 of the Springerville 1 portion of the Tucson Electric Power contract, which costs 10-11 cents/Kwh, and its replacement with cheaper purchases. The amount of economy energy also declines, however because the SWPL is projected to be filled with firm energy, so there is less room to deliver cheaper economy energy.

UCAN compares the value of power delivered over the SWPL to avoided cost, which is theoretically equal to the value of power that would have been generated in the absence of SWPL. This is not unlike our recently adopted cost-effectiveness standard for SONGS 1. The avoided energy cost used by UCAN for this comparison overstates the value of SWPL energy by 20 percent in order to be conservative and to reflect a value for avoided costs which assumes that SWPL is not in place. For avoided capacity costs, the full cost of a combustion turbine is used, $70/Kw in 1986, based on an average of SDG&E and PSD cost estimates, and escalated 7 percent per year. This results in a capacity value almost 15 percent higher than the capacity value adopted in this decision.

Table 2 shows that total SWPL cost exceeds total value by $50.1 million in 1986, $42 million in 1987, and $1.7 million in 1988. Although the cost of SWPL appears to be declining, the future long-term cost-effectiveness of the line depends on future SDG&E management decisions regarding replacement of contracts expiring in 1988-90 and the appropriate balance between firm and nonfirm energy delivered over the line in the future. UCAN believes and we are inclined to agree that the economics of SWPL will only improve if SDG&E has the incentive to negotiate reasonably priced firm power contracts and increase economy energy imports.

We will not now penalize SDG&E for signing up relatively expensive firm power contracts to the exclusion of additional economy energy purchases. The Commission will, however, reemphasize that the SWPL project was intended to provide cost-effective services and lower cost power. In fact, when the CPCN for SWPL was granted, it was thought that the line would provide little firm capacity and would be made cost-effective based on economy energy purchases. At that time the Commission found that SWPL would facilitate economy energy purchases, coal-fired power purchases, geothermal purchases, and enhance system reliability (D.93785).

SDG&E has now signed up so much expensive firm capacity that the transmission of sufficient economy energy to make the line cost-effective is almost impossible. This Commission agrees with UCAN's approach with some modification to ensure that the SWPL project provide valuable service and cost-effective power to SDG&E's customers. We also wish to ensure that the SWPL capacitor upgrade is made cost-effective in the near term as well as the future. UCAN concludes and we agree that an avoided cost cap incentive mechanism is necessary to make the SWPL project cost-effective, and to ensure that it will provide value and not costs to future ratepayers.

We must also review SDG&E's management of SWPL in light of that utility's resource strategy. The company rejoices in its decision to rely increasingly on purchased power to meet new load. We agree that certain ratepayer risks will be eliminated by the halt in construction of utility-owned generating facilities. We do not, however, want that risk replaced by the prospect of uneconomic power purchases. We note that in general our regulatory oversight has brought about the sharing of risks between shareholders and ratepayers. This is particularly true in the case of large rate base additions, such as SONGS. By changing its resource strategy, SDG&E management may have helped to cushion its investors from rate-base related risks. SDG&E should be aware though, that even though the price of energy is generally flowed through to ratepayers through the ECAC mechanism, the company is not excused from the rule that its decision to purchase energy must be reasonable in order to recover those costs from ratepayers.

The record shows that SDG&E has contracted to fill the SWPL's existing capacity with comparatively expensive firm energy at a cost over the utility's own avoided cost. In 1987, SDG&E is committed to take an additional 180 MW more than current SWPL capacity at prices which are uneconomic when measured against avoided cost. As a result, 85% of the upgraded capacity of the line will be used for contracted purchases. The utility should be encouraged to manage SWPL purchases so that they become cost-effective for present ratepayers as soon as possible. Conversely, current ratepayers should not have to bear more than the value of the power in their rates. This would be particularly unfair in this case as SDG&E is retiring several power plants and proposing to “store” 298 MW of capacity which could be re-activated at a capacity cost less than that of a combustion turbine.

Given the fact that SDG&E's total SWPL power costs are excessive by avoided cost standards, approval of the series capacitors will only exacerbate the burden of these uneconomic purchases on ratepayers. On the other hand, we find that SDG&E must be allowed to continue its out-of-state power purchases because such acquisitions play a major part in the utility's resource plan for baseload as well as economy power. We hope that as SDG&E becomes a more seasoned negotiator, the price of imported energy will come down. In the meantime, however, we will not force SDG&E's ratepayers to subsidize the company's learning curve.

We think that in order to restrict ratepayer costs to what is a reasonable cost of purchased power, to achieve intertemporal equity between ratepayers, and to give SDG&E the proper incentive to manage the SWPL line and ensure that it is a cost-effective resource, it is necessary to institute the SWPL Balancing Account.

Therefore, SWPL cost in excess of avoided costs, as described above, will be deferred in a balancing account with interest. We will adopt this treatment for the SWPL project. An explanation of the SWPL balancing account incentive mechanism and our alterations to UCAN's approach is in order.

The purposes of the SWPL balancing account are (1) to provide an avoided cost cap on SWPL power costs, and (2) to provide SDG&E with the incentives to significantly lower their power purchase costs. Ratepayers currently reimburse SDG&E for all SWPL ownership costs through base rates and all SWPL power purchase costs through the ECAC procedure. With the SWPL balancing account mechanism, revenues collected from rateplayers for SWPL ownership and purchased power costs will not exceed the avoided cost of energy and capacity received by ratepayers over the line. Because we continue to include SWPL ownership costs in base rates, and think it inappropriate to do otherwise, the SWPI balancing account must be used in conjunction with the ECAC/A&R process we currently employ.

We will adopt the “conservative” avoided costs proffered by UCAN to value SWPL energy. The 12,000 Btu/kWh incremental energy rate, and $70/Kw capacity cost escalated at 7 percent per year are generous to SDG&E.

Assuming that forecasted purchases equal actual purchases over SWPL during the 1986-88 period, under UCAN's proposal approximately $93.8 million will accumulate in the SWPL balancing account. This represents the difference between avoided costs appropriately adjusted and the total cost of SWPL energy.

The effect of this mechanism as proposed by UCAN is to provide SDG&E with incentives to reduce power purchase costs over the SWPL, to make power purchases over the SWPL cost-effective to current and future SDG&E ratepayers, and to make SDG&E whole in the longer term. Most importantly, it ensures cost-effectiveness to current and future ratepayers or at least makes ratepayers indifferent to power from SWPL or power from QF's. It is hoped that SDG&E will negotiate more vigorously to keep the cost of power purchased over SWPL down so as to achieve a zero balance in the SWPL account as soon as possible.

Interest on the monthly SWPL balances will be earned at the same rate as it earns on its ECAC balance. This treatment underscores the incentive aspect of the SWPL Balancing Account. Interest payments will make the utility whole even though its recovery for contractual expenses is deferred. Ratepayers will earn interest on their payments in excess of the value of SWPL power, since those sums are tantamount to loans to SDG&E. At the same time, the utility should not rely on SWPL balances to generate a stream of revenue for the company.

We will authorize the operation of the SWPL Balancing Account for five years with some modification. It is our objective that SWPL be managed so that it provides cost-effective power over the five-year term, if not sooner. If that is done, then the balance in the SWPL account should be zero. At the end of five years' time, we will review the outstanding balance in the SWPL account and determine what, if any, portion of those deferred revenues should be refunded to the utility.

The SWPL Balancing Account is our means of providing an incentive to SDG&E to lower the price of SWPL purchases. Given the portfolio of purchases that SDG&E has accumulated to date, the goal of achieving SWPL power at or less than avoided costs over a five-year term appears to be a reasonable one. That is not to say that SDG&E is immune from reasonableness reviews for those purchases to result if that goal is achieved. If SDG&E can negotiate purchases to result in a five-year average that is significantly lower than avoided cost but fails to do so, it will be subject to reasonableness review and disallowances.

Given the circumstances we are faced with today, in that the line is already built and contracts already executed, imposition of the above described cost effectiveness test is the most efficient protection for ratepayers that has been presented.

If at the end of five years there is still a balance in the SWPL account, those costs will be presumed to have been unreasonably incurred. The utility will bear the burden of rebutting that presumption. The net effect of the balancing account is (1) to give the utility the incentive to operate the SWPL cost-effectively, (2) to provide the utility the opportunity to recapture with interest any amounts paid for SWPL energy above avoided costs minus the cost of transmission, and (3) to convert to “soft earnings” a reasonable amount paid for energy over SWPL that is subject to recapture under the balancing account.

Our modifications to the UCAN proposal temper its effect. In order to reduce the rather substantial impact that UCAN's approach will have on SDG&E's “soft earnings” or cash flow the amounts that otherwise go into the SWPL balancing account in 1986 and 1987 will be amortized over 5 and 4 years, respectively. Interest on the amount not retained in the SWPL balancing account will be returned to ratepayers. For example, in 1986 SDG&E will enter one-fifth of the excess power purchase costs over avoided cost (minus transmission costs) in the SWPL account, retain four-fifths of the excess, and return to ratepayers interest on the outstanding uncollected amount. In the second year an additional one-fifth of the 1986 excess cost over avoided cost will be entered into the SWPL balancing account, and monthly interest on the remaining three-fifths will be returned to ratepayers. This will continue over 5 years, at which time the total 1986 purchase power cost in excess of avoided cost will have been entered into the SWPL balancing account. Interest will also accrue on the amount retained in the balancing account. With this exception, the SWPL balancing account mechanism as recommended by UCAN will be adopted for the specific case of SDG&E.

The other utilities servicing the state should not expect this type of treatment if similar instances occur. Given SDG&E's lack of experience with power purchases, we are inclined to give them a chance to increase their management acumen in this area, particularly because ratepayers can be made significantly better off.

The specifics of the SWPL balancing account mechanism are explained in detail in the 1985 ECAC decision.

We will emphasize that future SDG&E power purchases are subject to reasonableness review determinations and that we may not look favorably at large power purchases with high total costs (such as 11.1 cents/Kwh) in the future, particularly if such purchases encumber the line to the exclusion of reasonably obtaining sufficient economy energy. Furthermore, in the future we expect SDG&E to go well beyond just making SWPL cost-effective to make it an infra-marginal source of power.

We take this opportunity to express our general policy about future resource additions and power purchases for the state. The Commission is obviously concerned about the cost-effectiveness of resource additions, transmission lines, and purchased power agreements. This is in keeping with our concern to provide the state's ratepayers with least-cost energy supplies. Without overriding equity considerations, resources which are not cost-effective will be presumed to be unreasonable and subject to disallowance. The presumption of unreasonableness is not absolute and may be rebutted with an adequate showing. Likewise, if the cost of purchased energy exceeds the avoided cost less the cost of transmission, then we will presume that the excess is unreasonable and subject to disallowance.

We will also discuss some of the factors we will consider in reviewing the reasonableness of expenditures on transmission projects, as well as the reasonableness of the management of those lines. SWPL is only one of a number of transmission projects currently proposed or underway by utilities under this Commission's jurisdiction. We expect those utilities to act vigorously and prudently to assure benefits to the state's ratepayers during construction, contracting (where appropriate), and management of the transmission within the context of the utility's overall system.

The problem posed by SWPL is not unique. The full reasoning behind SDG&E's decision to sign expensive firm energy contracts was not explored on this record. However, we note that following construction SWPL was not initially fully loaded. Once built, of course, a resource potentially becomes subject to removal from rate base, if it is not used-and-useful. Thus once a transmission line is built, all other things being equal, leverage belongs to the seller of energy in any negotiations. Therefore, in order to ensure ratepayers and/or shareholders are protected from this potential, we expect California utilities to drive a hard bargain on both firm and economy energy sales in a timely fashion.

With respect to out-of-state power purchases, the Commission fully expects the states' utilities to go below the threshold of cost-effectiveness and provide lower cost or infra-marginal resources whenever possible. Certain low cost hydro and geothermal resources are examples of infra-marginal resources. Economy energy purchases or so called non-firm power contracts are also generally considered to be infra-marginal resources. We also acknowledge that the policy of the Commission to give ratepayers the benefits from infra-marginal resources-the difference between the infra-marginal resource cost and avoided cost.

In judging the reasonableness of the management of transmission line capacity, the Commission will take into account the avoided cost of the energy, at the time at which any applicable contracts were entered into, since the avoided cost represents the value of the power to ratepayers and therefore constitutes, absent special considerations, the ceiling price that should be paid. The Commission fully expects utilities to act vigorously to secure lower prices whenever possible. Before entering into long- or short-term contracts or transactions, we expect our utilities to make reasonable efforts to investigate regional energy markets as well as the economic and bargaining position of the selling utility.

One final matter remains. Because both SDG&E and Staff have not addressed the directive set forth in D.84-12-065, we will again direct applicant and Staff to review the reasonableness and the purported economic savings of SWPL for the 1984-85 and 1985-86 periods during the 1986 ECAC reasonableness review.

XXI. *Productivity*

We expect SDG&E to implement as many of the recommendations of the Ernst & Whinney management audit as is feasible. Recommendations characterized as most cost-effective should be implemented first. While in this decision, the Commission will not impute general productivity factors or adopt Total Factor Productivity (TPF) adjustments, we highly recommend that SDG&E examine the reasons why their relative performance in various categories of productivity seems suboptimal in comparison with other California utilities. Specifically, we refer to A&G expenses per Kwh sales, total production expenses per Kwh sales, total O&M expenses per customer, and total O&M expenses per Kwh. We will expect SDG&E to develop productivity measurement tools and standards in the future and to provide a showing on productivity in the next rate case.

Findings of Fact

1. By this application, SDG&E requests annual increases of $55,418,000 for the Electric Department, $21,720,000 for the Gas Department, and $1,487,000 for the Steam Department for the test year 1986.

2. Between February and September, 1985, public hearings were held at which all parties including the public were given an opportunity to participate.

3. The sales and revenues for the test year were agreed to by the parties.

4. The sales and revenues for the test year are shown in Appendix B [omitted] herein.

5. The following are the escalation rates for 1984, 1985, and 1986:

	Labor	*Nonlabor*
1984	5.5%	3.9%

1985	5.5	2.9
1986	3.9	3.7

6. The Customer Masterfile Conversion and the Information System Program are one-time extraordinary expenses.

7. The Community Outreach Program offers substantial benefits to SDG&E's hardship customers and is a reasonable operating expense.

8. There is not sufficient evidence to conclude that there will be an additional 12,000 calls related to "high bills".

9. There is no need to transfer $1.2 million to the Customer Accounting and Collection accounts from the conservation accounts.

10. The "Bad Debt Match" program proposed by the company is premature.

11. The uncollectible factor for the test year is .200%.

12. SDG&E experienced a growth of customer and sales as follows:

		Sales	*Customers*
Electric	1984-1986	.022	.028%
Gas	1984-1986	.073	.016

13. There is a relationship between A&G expenses and the amount of sales and number of customers.

14. A cap on the growth of certain A&G expenses equal to the growth in customers produces a reasonable estimate of future expenses.

15. The staff adjustments to the company's estimates for administrative salaries and expenses are reasonable.

16. To estimate Account 922 (transfer account), the transfer ratio must match the period which serves as a base for the estimate for Accounts 920 and 921.

17. The payment to Booze, Allen, and Hamilton for preliminary management audit work was not unreasonable.

18. Recovery of past period in-house costs associated with the management audit is not a proper test year expense.

19. Recovery of the remaining costs are a one time extraordinary expense to be recovered over the three-year rate case cycle.

20. SDG&E's method of calculating pensions and medical costs is correct.

21. The employee savings plan is not a proper form of employee compensation for ratemaking purposes and will be capped at the 1985 level with the expectation that a different form of compensation may be negotiated with the employees.

22. The stipulated level of company contributions to various organizations represents a reasonable level of such expenses for any similar on-going enterprise.

23. Franchise fees incurred on past interdepartmental sales are not reasonably certain to be paid during the forecast test year.

24. The company/staff stipulated expense level for regulatory expenses reflects an increasing level of complexity in this area and is reasonable.

25. $2.8 million is a reasonable level of minimum bank balances for 1986.

26. The rate of increase in bank fees is now slowing.

27. $670,000 is a reasonable estimate for bank fees for the test year.

28. Membership in EEI and AGA provides both ratepayer and shareholder benefits.

29. It is reasonable to allow SDG&E to recover 75% of its EEI and 99% of the non-advertising portion of its AGA

dues.

30. Some portion of any dues to EEI and AGA contributed by ratepayers will be used for purposes not in the ratepayers best interest.

31. NARUC is currently studying the proper ratemaking treatment for dues paid to AGA and EEI.

32. SDG&E's method of choosing and prioritizing research projects is reasonable.

33. A 1986 expenditure of $4,242,000 ($83) will provide for an adequate research design and development program for SDG&E.

34. SDG&E's method of choosing and prioritizing research projects is basically sound.

35. The staff adjustment to Account 932 (A&G maintenance) is reasonable.

36. Some growth in the program associated with cogeneration is necessary.

37. Operating and Maintenance, and Administration and General expenses associated with nuclear generation have been agreed to by the staff and the company and are reasonable.

38. The company's estimates for Technical Services and the staff's estimates for Power Plant Projects and Overhaul Expenses are reasonable.

39. Fuel handling expenses vary by the amount of fuel projected to be burned by a greater amount than projected by the company.

40. $767,000 is a reasonable estimate for fuel handling expenses in the test year.

41. There is no maintenance backlog for transmission substations.

42. The staff estimate appears more reasonable than the company's estimate for substation maintenance.

43. The staff estimate for the expense of overhead line maintenance which is 40% greater than the 1984 figure is more reasonable than the company's estimate which projects an increase of 50% over 1984 levels.

44. The company's estimate of the expenses “transmission by others” based on three-year historical growth is better than the staff's estimate based on nonlabor escalation factors.

45. Deferred accounts for base rate expense items are implemented only in extraordinary circumstances.

46. Estimation of the fixed wheeling expenses is not such an extraordinary expense that we will maintain a deferred account for this item.

47. The company estimates for the DFIS project are reasonable.

48. The staff's estimating method for the remaining portion of Account 588 is more appropriate than the company's.

49. The staff's estimate for “overhead line maintenance” Account 593 assumes that only the class “A” violations can be corrected within the rate case cycle.

50. It is reasonable to maintain an 18-month tree trimming cycle and the expenses for this level of activity are reasonable.

51. The remainder of the staff's estimates in distribution expenses are better than the company's except where the staff failed to normalize expenses.

52. South Bay 3 is sufficiently useful to remain in rate base as plant held for future use.

53. A reasonable amortization for prematurely retired plants is five years.

54. Our determination pursuant to D. 84-12-065 is that the purported savings from SWPL do not exist for the 1986-88 period.

a. A balancing account incentive mechanism is needed to ensure that the SWPL line and capacitor upgrade are cost-effective to present and future ratepayers.

b. The SWPL balancing account will ensure that the capacitor upgrade is an addition of value and cost-effective for SDG&E ratepayers.

c. Avoided costs adjusted to approximate the absence of the SWPL project are an appropriate measure for the value of SWPL energy.

d. Consideration of the use of the SWPL in the rate case is appropriate in light of the need to consider related resource planning, management, and rate base issues concurrently.

e. SDG&E should ensure that power purchases and total SWPL costs are at least less than appropriately valued avoided costs.

f. The SWPL will result in substantial rate increases to SDG&E ratepayers without corresponding benefits if an adjustment mechanism is not employed.

g. Total SWPL costs will significantly exceed total SWPL value if an adjustment mechanism is not utilized.

h. The SWPL incentive mechanism will direct SDG&E toward obtaining lower cost power purchases from the southwest.

i. When SDG&E reduces SWPL energy cost to less than avoided costs, the difference between avoided costs and total SWPL power costs will be refunded from the SWPL balancing account.

j. To ensure cost-effectiveness and that the SWPL line and capacitor upgrade are used and useful the SWPL balancing account must be used in conjunction with the ECAC/AER process.

k. If the cost of purchased power exceeds the avoided cost less the cost of transmission a rebuttable presumption is created that the excess is unreasonable and subject to disallowance.

l. Amortization of portions of the 1986 and 1987 SWPL power costs in excess of avoided cost minus the cost of transmission is appropriate at this time so that SDG&E's “soft earnings” are maintained.

m. The staff and applicant are directed to review the purported economic savings of the SWPL project for the 1984-85 and 1985-86 periods during the 1986 ECAC reasonableness review, in light of the presumption that purchase power costs in excess of avoided costs minus the cost of transmission are unreasonable.

n. After 5 years the Commission will review the SWPL account balance and if any balance remains, it will be presumed to have been unreasonably incurred.

55. A $1,304,737,500 figure is a reasonable estimate for electric rate base for the test year.

56. A $193,525,400 figure is a reasonable estimate for gas rate base for the test year.

57. A $687,000 figure is a reasonable estimate for steam plant for the test year.

58. The Encina 5 gasification and pipeline project will be completed in August 1986.

59. The Beach Cities Project will be completed as of July 1986.

60. The company has completed a sale of streetlights to the City of San Diego.

61. The staff's estimate of common plant additions and retirements is reasonable.

62. At present, there are no guidelines for the length of time that property can be held in “plant held for future use” accounts.

62a. Plant held for future use without a definite plan for use within a reasonable time should be excluded from ratebase.

63. The UCAN estimate for customer contributions is based on a superior estimating equation.

64. The projected year 1985 is a proper base for estimate of accounts payable.

65. Materials and supplies are included in rate base.

66. In-house expense items associated with the Materials and Management System will not occur in the test year.

67. A stay-the course policy is appropriate for conservation and load management.

68. “Stay the course” means expenditures for the test year

at about the same level as at present.

69. An expenditure level of $16,563,000 ($83 - 000) for 1986 for conservation, load management, and Demand Side Management is reasonable.

70. The functions of Gas Serviceman and Turn-on Meterman functions can be merged by 1988.

71. The company requires 14 draftsmen for the gas department.

72. The staff's capitalization ratios and cost of debt and preferred stock are reasonable.

73. A rate of return on equity of 15.0% producing an overall rate of return on rate base of 12.37% is reasonable.

74. The adopted results of operation shown in Appendix B [omitted herein] are reasonable for the test year 1986 and revenues generated should provide SDG&E with the opportunity to earn the authorized rate of return of 12.37%.

75. Revenues allocated on the basis of marginal costs provide a better price signal than revenues based on embedded costs.

76. Company specific marginal generation costs are more accurate than the marginal generation costs based on statewide average data.

77. Marginal customer costs are those costs that change with small decrease in the number of customers.

78. There is no standard uniform method of calculating system reliability presently.

79. The LOLP standard of one day in ten years is dependent on a proper calculation of system reliability.

80. The measure of system reliability should not differ according to its various uses.

81. The measurement of and standards for system reliability should incorporate the concepts of value and cost-effectiveness.

82. Until a better management of system reliability is before us, the value of additional QF capacity can be based on the full cost of a CT and will be amended later by advice letter filing when this issue is resolved in the long-run OIR-2 proceeding.

83. The utility resource plan is not considered adequate as presented in this proceeding for the long term.

84. The value of QF supplied capacity is based on the full cost of a CT until the advice letter filing.

85. Marginal customer as currently defined costs do not provide appropriate or accurate economic signals to existing customers.

86. The electric revenue requirement can be allocated to the customer classes on the basis of full marginal costs less marginal customer costs (100% EPMC) without undue inequity to any customer class.

87. The SAPC method of allocating changes in the revenue requirement between general rate cases will maintain class relationships established in general rate cases.

88. Application of the SAPC method of allocating changes in the revenue requirement between general rate cases will prevent the necessity of reviewing marginal costs levels and other allocation methods.

89. Customer charges do not provide economic signals relevant to the cost of production of electricity.

90. Customer charges can result in commodity rates moving closer to marginal costs absent “baseline” type adjustments.

91. There is no compelling need presented in this case to institute a customer charge for the residential class.

92. Large baseline quantities require high baseline rates to produce a reasonable relationship between Tier I and Tier II rates.

93. In order to maintain baseline quantities with the parameters of the legislation, usage patterns must be reviewed at least as often as the occurrence of general rate cases.

94. Baseline changes which take place slowly will alleviate customer hardships.

95. The submetering discounts for schedules applicable to mobilehome parks as calculated by SDG&E without a diversity adjustment are reasonable.

96. The service establishment charges proposed by the company are reasonab1e except for the change of account without a meter read.

97. The service establish charge for a change of account without a meter read at $5.00 will recover the appropriate cost.

98. The customers on the TOU schedules require a large degree of rate structure stability to incorporate the rate signals into the customers' operations.

99. Customers' needs and opinions have not been adequately considered in the design of TOU rates.

100. Load management programs and rate design have not been adequately integrated.

101. The current commodity rates understate the variation in cost by time period.

102. Rate structure stability can be provided through consistent Commission policy and by holding the customer charges and demand charges relatively constant and applying any revenue decrease to the mid-peak and off-peak commodity rates.

103. The costs of standby service provided to cogenerators is the same as the cost of standby service provided to non-cogenerators.

104. The staff's proposal for increased standby charges with demand charge waivers more accurately reflects the cost of standby service than the other proposals in this proceeding.

105. More effort and experience in "marketing" TOU rate programs is needed in order to arrive at rate structures that reflect costs and are acceptable to and understandable by customers.

106. The various services associated with streetlighting can be "unbundled" and separate charges provided for specific services.

107. "Unbundling" streetlighting services will provide customers a wider range of service options.

108. The replacement cost-new less depreciation method of valuing streetlight facilities for rate design purposes is a better approximation of the marginal facilities cost than "original cost less depreciation".

109. Facilities charges provide more accurate signals if based on marginal costs.

110. The gas design issues of 1. submetering discounts, 2. collection charges, and 3. service establishment charges are identical to the same issues for electric service.

111. The adopted revenue requirement for the steam department requires a 100% increase in steam rates.

112. A 100% increase in steam rates is excessive.

113. The steam rate increase can be phased in by delaying the increase for one year.

114. Transferring the balance in the steam balancing account to the appropriate electric balancing account when service is completely phased-out will fully recompense the company.

115. The electric and steam rates in Appendix C are just and reasonable.

Conclusions of Law

1. SDG&E should file revised jurisdictional electric rates which are designed to produce a revenue requirement of $639,351,000 for the year 1987. Because of the one-time conservation funds amortization, the revenue requirement for 1986 is $638,207,000.

2. SDG&E should be allowed to file revised gas rates as set forth in the concurrent decision on SDG&E's A.85-09-045 CAM proceeding which includes the additional revenue requirement of $3,272,000 found reasonable herein.

3. All motions not yet ruled on are denied.

ORDER

IT IS ORDERED that:

1. San Diego Gas and Electric Company (SDG&E) is authorized and directed to file with this Commission, on or after the effective date of this order, revised tariff schedules for electric and steam rates as set forth in this decision.

2. SDG&E is authorized and directed to file with this Commission, on or after the effective date of this order, revised tariff schedules for gas rates as set forth in the concurrent decision on SDG&E's A.85-09-045 Consolidated Adjustment Clause proceeding which includes the additional revenue requirement authorized herein.

3. The revised tariff schedules shall become effective 5 days after filing but not earlier than January 1, 1986.

4. The revised tariff schedules shall apply to service rendered on or after the effective date of the revised tariff schedules.

5. SDG&E shall carry over with interest unspent funds for conservation, load management, and CVR conversion programs into the attrition year.

This order is effective today.

Dated December 20, 1985, at San Francisco, California.

DONALD VIAL

President

VICTOR CALVO

PRISCIALLA C. GREW

WILLIAM T. BAGLEY

FREDERICK R. DUDA

Commissioners

I abstain in part./s/ PRISCILLA C. GREWCommissionerI dissent in part./s/ WILLIAM T. BAGLEYCommissioner

APPENDIX A

List of Appearances

Applicant: *William L. Reed*, Attorney at Law, for San Diego Gas & Electric Company.

Interested Parties: *Judith Alper*, Attorney at Law, for herself; *Norman J. Furuta*, Attorney at Law, for Federal Executive Agencies; Biddle & Hamilton, by *Richard L. Hamilton*, Attorney at Law, for Western Mobilehome Association; *James Hodges*, for California/Nevada Community Action Association; *Frederick E. John*, Attorney at Law, for Southern California Gas Company and Pacific Lighting Gas Supply Company; *William L. Knecht*, Attorney at Law, for California Association of Utility Shareholders; Manuel Kroman, John W. Witt, City Attorney, and *Leslie J. Girard*, Attorney at Law, for the City of San Diego; *William B. Marcus*, for Economics Consulting Services; *Michael D. McCracken*, Attorney at Law, and Reed V. Schmidt, for California City-County Street Light Association; *John D. Quinley*, for himself; *Donald G. Salow*, for Association California Water Agencies; *Gary Simon*, for El Paso Natural Gas Company; Beers & Dickson, by *Joel R. Singer*, Attorney at Law, for Utility Consumers' Action Network; *Harry K. Winters*, for University of California; *Bill Wright*, for Borrego Spring LNG Users; *Skip Daum*, for the Insulation Contractors Association; *Philip R. Mann*, Attorney at Law, for P.R. Mann & Associates; *Larry C. Mount*, Attorney at Law, and R. P. Haub, for Southern California Edison Company; *Edward J. Neuner*, for himself; R&W Consultants, by *Paul A. Weir*, for San Diego Mineral Products Industry Coalition; Graham & James, by *Enid Goldman*, Attorney at Law, for Kelco Division of Merck & Company, Inc. and Independent Power Corporation; Hanna and Morton, by *Douglas K. Kerner*, Attorney at Law, and *David Branchcomb*, for Independent Energy Producers Association; *Steven M. Cohn*, Attorney at Law, for the California Energy Commission; *Louise Fyock*, for Project J.O.V.E., Inc., *Howard V. Golub*, Attorney at Law, for Pacific Gas and Electric Company; *Michel Peter Florio*, Attorney at Law, for Toward Utility Rate Utilization; *Matthew V. Brady*, Attorney at Law, for the State of California Department of General Services; *Kevin B. Belford*, Attorney at Law, for American Gas Association; *James H. Byrd*, Attorney at Law, for Edison Electric Institute; and Brobeck, Phleger & Harrison, by *Richard C. Harper*, Attorney at Law, for California Manufacturers' Association.

Commission Staff: *Timothy E. Treacy*, *Peter Arth*, Attorneys at Law, and *Raymond Charvez*.

FOOTNOTES

FN1 Rates used per additional direct testimony of Lee Haney (June '85).

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