ALJ/jc/bg

Decision 84-12-060 December 28, 1984

ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of SOUTHERN CALIFORNIA EDISON COMPANY for Authority to Establish a Major Additions Adjustment Clause, to Implement a Major Additions Adjustment Billing Factor and an Annual Major Additions Rate to Recover the Costs of Owning, Operating, and Maintaining San Onofre Nuclear Generating Station Unit No. 2 and to Adjust Downward Net Energy Equal the Increase in Major Additions Adjustment Clause Rates.

Application 82-02-40
(Filed February 18, 1982;
amended December 1, 1982
and October 4, 1983)

And Related Matters.

Applications
83-10-36
82-03-63
83-10-12
83-11-19

(For appearances see D.83-09-007 and D.84-03-059.)

INDEX

CORRECTION

CORRECTION

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INDEX

PHASE 1B INTERIM OPINION

I. Introduction

On February 18, 1982 Southern California Edison Company (Edison) filed Application (A.) 82-02-40 with the Commission to recover the costs of owning, operating, and maintaining San Onofre Nuclear Generating Station Unit 2 (SONGS 2). San Diego Gas & Electric Company (SDG&E) filed its companion application, A.82-03-63, for its 20 percent interest in SONGS 2 on March 18, 1982. On September 7, 1983 the Commission issued Decision (D.) 83-09-007 establishing the Major Additions Adjustment Clause (MAAC) procedures and initial MAAC rates. The decision also established a Phase 1B for these proceedings to consider the need for a cap for the target capacity factor (TCF) procedure adopted in that decision as well as to consider the possibility of adopting an alternative ratemaking methodology other than conventional straight-line depreciation original cost (SLDOC or conventional) ratemaking.

On October 4, 1983 Edison made a supplemental filing in A.82-02-40 to reflect 1984 investment and noninvestment-related cost figures for SONGS 2. On October 5, 1983 SDG&E filed A.83-10-12 requesting similar updating of SONGS 2 costs. On October 21, 1983 Edison filed A.83-10-36 requesting that SONGS 3 be given similar MAAC treatment from the commercial operating date (COD) of SONGS 3 through December 31, 1984. Similarly, SDG&E filed A.83-11-19 on November 4, 1983 for MAAC treatment for its 20 percent interest in SONGS 3. These matters were consolidated for hearings in Phase 1B.

During the course of the hearings, certain items were the subject of stipulation and/or interim decision. D.84-01-038 dated January 5, 1984, authorized Edison and SDG&E to accrue in the MAAC balancing account the additional investment-related costs for SONGS 2 not previously considered in D.83-09-007, subject to reasonableness review in Phase 2. D.84-03-017 dated March 7, 1984 authorized Edison and SDG&E to include SONGS 3 as a specified major addition under the

MAAC tariff and also authorized inclusion of investment-related-costs for SONGS 3 in the MAAC balancing account when the COD criteria has been met. On March 6, 1984 Edison, SDG&E, and the Commission staff (staff) filed a stipulation recommending the adoption of the staff's estimates for noninvestment-related expenses for SONGS 2 & 3 for 1984. D.84-03-059, dated March 21, 1984 implemented those noninvestment-related expenses as well as investment-related rates to the extent of the then estimated fuel savings from the operation of SONGS 3. D.84-05-055, dated May 16, 1984, authorized certain additional noninvestment-related expenses for SDG&E due to billing of home office expenses by Edison which were not considered previously. The decision further increased investment-related rates to the extent of the additional fuel savings stipulated to by SDG&E and the staff. Finally, Edison, SDG&E, and staff stipulated to the use of the investment-related amounts for interim use in the MAAC balancing account calculations subject to further reasonableness review in Phase 2.

With the stipulations and interim decisions, the evidentiary hearings were focused on the following key issues in Phase 1B:

1. The need for alternate capital recovery methods; and
2. The need for a cap and/or modifications to the TCF.

In addition a remaining issue, briefed earlier in 1984, on whether D.84-01-034 which authorized deferred debit accounting for SONGS 2 constituted retroactive ratemaking needs to be addressed in this order.

II. Summary of Decision

This decision authorizes Edison and SDG&E to increase their MAAC Ownership Rate tariffs for SONGS 2 & 3 investment-related costs by $300.0 million and $84.0 million, respectively. The increase in Edison's MAAC rate will be mitigated by the expected decrease in Edison's base rates. These rates are to become effective on January 1, 1985. The Commission considered various alternative ratemaking treatments for SONGS 2 & 3 in Phase 1B, and we have decided that use of the trended rate base approach proposed by staff, although it has many attractive features, is not suitable in light of current circumstances. The addition of SONGS 2 & 3 to rate base will be treated in the conventional manner. The rate increase authorized will still leave a substantial undercollected balance in the MAAC balancing accounts and will enable the Commission to have sufficient flexibility to cope with possible disallowance should Phase 2, the reasonableness review, result in disallowances of any investments in SONGS 2 & 3.

The decision adopts the TCF procedure for SONGS 3. The decision rejects a proposal to place cap on the benefits or costs resulting from the TCF mechanism. Benefits and costs will continue to be shared equally by ratepayers and investors.

The decision also clarifies the relationship between the Annual Energy Rate (AER) and the TCF by stating that the TCF would only apply to the replacement energy cost not subject to the AER. The decision also adopts certain specific economic modifiers, provides for capacity factor calculations to be made for each utility separately in proportion to each utility's ownership share and in proportion to the production taken.

The decision also finds that the deferred debit accounting order made in D.84-01-034 relating to SONGS 2's costs between the COD of SONGS 2 and the date that the rates authorized by D.83-09-007 took effect constituted unlawful retroactive ratemaking.

III. Procedural Summary

Public hearings on the consolidated applications were held in Los Angeles on November 16, 1983 and January 5, 1984 and in San Diego on January 6, 1984 for the purpose of taking public witness testimony. Prehearing conferences were held in San Francisco on January 12 and February 9, 1984. Evidentiary hearings commenced on March 6, 1984 and concluded on June 1, 1984, subject to the filing of briefs and oral argument before the Commission en banc on September 13, 1984. Further Phase 2 hearings on the reasonableness and prudence of the investment costs for SONGS 2 & 3 are expected to commence in 1985.

Concurrent opening Phase 1B briefs were filed on July 2, 1984 by Edison, SDG&E, City of San Diego (City), Harold Boxer, and the staff. Concurrent reply briefs were filed by Edison, SDG&E, and staff. The same parties plus Consumers Coalition of California, Toward Utility Rate Normalization (TURN) and Mr. Duncan also participated in the oral argument. The matter is now ready for decision.

IV. Retroactive Ratemaking

A. General

In D.84-01-034 issued January 5, 1984, an order modifying D.83-09-007 and denying rehearing, the Commission expressed concern that "there may be a retroactive ratemaking problem if we allow Edison to retroactively record costs for the period between staff certification of our COD criteria and either the date D.83-09-007 was issued (September 7) or the date the MAAC rates became effective (October 10). No one has formally addressed this issue; therefore we will order Edison, SDG&E, our staff, and any other parties interested in doing so, to brief this issue pursuant to a schedule established by the ALJ". The ALJ at the prehearing conference on January 12, 1984 ordered that concurrent opening briefs be filed no later than

February 17, 1984 with concurrent reply briefs due on March 2, 1984. Opening briefs were filed by Edison, SDG&E, City, and staff and concurrent reply briefs were filed by Edison, SDG&E, and staff.

B. Background

On June 14, 1982, the ALJ issued a ruling setting a COD criteria for SONGS 2. That ALJ Ruling was ratified by the Commission by Minute Order on July 21, 1982 and subsequently confirmed by D.82-09-111. Evidentiary hearings on Phase 1 relating to the adoption of a MAAC commenced on January 17, 1983 and concluded on April 7, 1983 subject to receipt of briefs and oral arguments and further hearings in Phase 2 on the reasonableness and prudence of the investment in SONGS 2 at some future date. On August 8, 1983 Edison released SONGS 2 to Edison's system dispatcher for firm operations. Under Federal Energy Regulatory Commission (FERC) accounting rules the plant was considered to be plant in service for accounting purposes. Ten days later, on August 18, 1983, SONGS 2 completed its 200-hour run at 100% power thereby achieving the Commission's COD criteria. On September 6, 1984 a staff member visited SONGS 2 to review the plant operating records and confirmed that SONGS 2 had met the Commission's COD criteria on August 18, 1983.

On September 7, 1983 the Commission issued D.83-09-007 authorizing Edison and SDG&E to establish a MAAC balancing account procedure to reflect certain ownership costs for their respective interests in SONGS 2. The decision authorized MAAC rates equivalent to the estimated fuel savings resulting from the commercial operations of SONGS 2 of $206.9 million for Edison and $61.7 million for SDG&E. Of these totals, $38.2 million represented revenues to cover noninvestment-related expenses not subject to balancing account treatment for Edison and a corresponding $10.7 million for SDG&E. The remaining revenues were for investment-related costs and are subject to balancing account treatment.

In Finding 79 in D.83-09-007 the Commission stated "Should the COD be met prior to the issuance of this decision, it is reasonable for applicants to continue accruing Allowance For Funds Used During Construction (AFUDC) on SONGS 2 investment, capitalize operating and maintainance expenses, and credit any energy generated by SONGS 2 at avoided costs to the work order until MAAC rates become effective".

Subsequent to the issuance of the decision, Edison and SDG&E both filed applications for rehearing. Among the issues raised by applicants was the need to amend the decision to avoid conflicts with FERC accounting regulations because of the Commission's adoption of a 50-50 allocation of common plant costs between Units 2 & 3, and the timing difference between the plant in service date for accounting purposes (August 8, 1983) and the COD (August 18, 1983) as required by the Commission. Edison requested that Finding 79 be changed to delete language calling for the continued accrual of AFUDC and the capitalizing of the operating and maintenance expenses to the work order since it would be contrary to the Uniform System of Accounts and to permit accrual of such expenses in a deferred debit account. Edison further requested that depreciation expense from the in-service date for accounting purposes to the date rates are fixed pursuant to D.83-09-007 also be accrued in the deferred debit account. Edison also requested that Ordering Paragraph 4 be similarly revised.

In granting the modification sought by Edison, the Commission added a new Finding 26a and modified Finding 79 as requested by Edison subject to the provision that the ratemaking to be given these accounts will depend on the determination of whether and between what dates compensation for such expenses would constitute retroactive ratemaking. The Commission further revised Ordering Paragraph 4 and added a new Ordering Paragraph 4a to correspond to the changes made in Findings 26a and 79.

C. Edison's Position

Edison sees the issues on retroactive ratemaking as:

a. Does the action of the Commission in D.84-01-034 in authorizing Edison to record in a deferred debit account for the period August 18, 1983 through October 8, 1984, amounts equivalent to AFUDC as well as other expenses prescribed in Finding Numbers 26a and 79, constitute retroactive ratemaking?

b. Would any future California Public Utilities Commission's (CPUC) action recompensing Edison through the MAAC balancing account procedure for such amounts so recorded in such deferred debit account, constitute retroactive ratemaking?

Edison argues that the Commission in authorizing Edison to accrue an amount equivalent to AFUDC in a deferred debit account does not constitute ratemaking at all, let alone retroactive ratemaking. Edison argues that no one questions that SONGS 2 costs incurred prior to August 8, 1984 can be recorded in the MAAC balancing account for consideration in rates to be established in the future by the CPUC. The Commission has now raised the spectre that costs incurred during the period August 18, 1983 and October 8, 1983 for consideration in rates to be established at a later date would constitute retroactive ratemaking. Edison states that conceptually there is no difference between MAAC balancing account treatment of pre-August 8, 1983 costs and the deferred debit accounting for post-August 17, 1983 SONGS 2 costs. Edison argues that the Commission in authorizing deferred debit accounting of post-August 17, 1983 costs has not engaged in ratemaking and therefore the proscription of Public Utilities (PU) Code § 728 has no application to D.84-01-034.

Edison argues that the Southern California Edison v Public Utilities Commission, 20 Cal. 3d 813 (1978 Edison Case) most closely resembles the MAAC procedure involved in this proceeding. Based on the authority of the 1978 Edison Case, Edison submits that SONGS 2 MAAC type costs incurred during the period August 18, 1983 and October 8, 1983 can be included in the MAAC balancing account and be considered in the rates to be established by the Commission in the future. Edison bases this conclusion on the following:

a. The 1978 *Edison* Case holds that the proscription against retroactive ratemaking applies only to general rate cases and not to the act of promulgating rates pursuant to a balancing account procedure.

b. The ultimate future ratemaking action contemplated by the Commission in its Findings 26a and 79 of D.84-01-034 will relate to the Commission's disposition of the MAAC balancing account.

c. It is clear that such ultimate ratemaking action will affect costs reflected in the MAAC balancing account which were incurred in the months and years prior to August 8, 1983.

d. A fortiori, there is no rational basis for such future MAAC ratemaking actions not to reflect costs reflected in the MAAC balancing account which were incurred on or after August 8, 1983.

e. Edison further states that the determination of when SONGS 2 went into service for FERC accounting purposes was not an arbitrary action by Edison, but predicated on the date when SONGS 2 was released to the system dispatcher for firm operation.

D. SDG&E's Position

SDG&E takes the position that the expense treatment authorized by the Commission in D.83-09-007 and the accounting treatment adopted in order to implement that expense treatment, are clearly within the authority of the Commission, and the recovery of those expenses does not constitute retroactive ratemaking between any of the dates in question.

SDG&E argues that the only dates where a retroactive ratemaking issue potentially exists is limited to the period between August 18, 1983 and September 7, 1983, the date of D.83-09-007. SDG&E states that capital type expenditures accumulated in the deferred debit accounts prior to August 8, 1983 were being charged to construction budget and therefore capitalized. SDG&E argues that the change which took place in August was a matter of accounting convention rather than in the nature and type of costs experienced by the companies. The expenses in question were not a product of a general ratemaking proceeding. SDG&E further argues that by authorizing a continuation of capitalization, the Commission's avowed intention was to have the utilities recover these capitalized costs, as opposed to a ratemaking order with regard to these costs. As capitalized or quasi-capitalized expenses, SDG&E alleges that the Commission's final ratemaking with regard to these costs will not occur until a final capital decision is made on SONGS 2.

SDG&E states that the Commission authorized the deferred debit accounting for the purpose of allowing a proper alignment of the cost recovery intended by the Commission with the accounting rules required by FERC. The disallowance of any of these expenses based upon a retroactive ratemaking fiction would be due to the Commission's inability to set capitalization rules on a timely basis, not due to recovery of past noncapital expenses against future ratepayers. The deferred debit account merely continues capital procedures until a decision on investment can be reached by the Commission, therefore, it clearly does not constitute retroactive ratemaking.

SDG&E further alleges that the Commission's postponement of hearings on investment-related issues in this proceeding impliedly preserved the Commission's right to decide those issues. While the Commission did not explicitly preserve its right to decide on the quasi-capital expenses in question, deferral of future hearings on the investment in SONGS-2 certainly implied the Commission's intent to decide on those investment costs. SDG&E reasons that the Commission could not specifically preserve the issue on deferred-debit accounts in detail because it could not foresee the exact nature and timing of future hearings and the eventual decision.

E. City of San Diego's Position (City)

The City takes the position that allowing applicants to retroactively record costs for the period between the staff certification of the COD (August 18, 1983) and the date D.83-09-007 was issued September 7, 1983 would definitely violate the rule against retroactive ratemaking. The City argues that allowing applicants to recover pre-September 7, 1983 costs that are not the result of a previously established deferred debit or balancing account will violate the rule against retroactive ratemaking and that the reasonableness of the pre-September 7, 1983 costs is not the issue.

The City argues that the California Supreme Court has consistently held that the Commission sets rates prospectively and not retroactively. Allowing applicants to recover the already expended pre-September 7, 1983 costs would be contrary to PT&T Co. v Public Utilities Commission, 62 Cal. 2d 634, 650 (1965) as the rates would be prospectively designed to recover past expenditures. The City concludes that while it may be reasonable for applicants to accrue in a deferred debit acount AFUDC on SONGS 2 investment, operating and maintenance expenses, property and payroll taxes, nuclear fuel expenses, a credit for any energy generated by SONGS 2 priced at avoided costs and depreciation expense from August 18, 1983 to September 7, 1983, allowing compensation for such expenses would constitute retroactive ratemaking.

F. Staff's Position

The Legal Division argues that the Commission is properly concerned that authorizing applicants to establish a deferred debit account for SONGS 2 prior to the effective date of D.83-09-007 on September 7, 1983 constitutes retroactive ratemaking. The staff cites PT&T v PUC (1965), City of LA v PUC (1972), and SCE v PUC court decisions which forbid retroactive ratemaking and reaffirmed the Commission's authority to fix rates prospectively only.

The staff argues that whatever reasons the Commission might have had for wanting to grant Edison and SDG&E rate recovery for any period prior to September 7, 1983 are irrelevant; and that the Commission simply lacks the power to issue a retroactive ratemaking order. Therefore, Findings 26a and 79 of D.84-01-034 constitute retroactive ratemaking to the extent that they refer back to an August 18, 1983 date. The staff further raises the question whether Edison and SDG&E may lawfully charge rates prior to the date the MAAC rates became effective on October 10, 1983. While the Commission had authority to create the deferred debit accounting procedure in D.83-09-007, by failing to do so, the staff argues that the Commission lost the opportunity. The staff further argues that since utilities may lawfully collect rates only pursuant to their filed tariffs, the Commission cannot retroactively authorize Edison and SDG&E to revise the tariffs made effective on October 10, 1983. The staff argues that the tariff is a contract between the utility and its customers. Consequently, the customers of Edison and SDG&E can have no obligation to pay rates in tariffs until they are filed and made effective. Since the MAAC procedures were not effective until October 10, 1983, Edison and SDG&E had no contract with their customers prior to that date to collect MAAC revenue.

G. Discussion

The retroactive ratemaking question arises only because of the unusual treatment the SONGS plants have received. In resolving this issue, we find it helpful to contrast the treatment of SONGS with that of a typical plant addition.

More typical additions to rate base are treated in one of two general ways. We may review the reasonableness of construction and related costs and forecast an in-service date in the utility's general rate case or attrition case preceding the operation of the plant. Alternatively, we may review the costs and usefulness of the asset in the general rate case or attrition case following start-up.

The first treatment creates a substantial risk for ratepayers and the utility because we must necessarily rely on projected costs and a projected in-service date. For many additions to plant, both the costs and start-up may be predicted with an acceptable degree of accuracy. But inaccuracies will exist, with financial implications for ratepayers and shareholders. For example, if the actual start of commercial operation of a generating plant occurs later than the projected in-service date, ratepayers will have overpaid the utility for the plant, and shareholders will receive a return on an investment that is not actually used and useful. On the other hand, if the projected costs of the plant are understated in comparison with the actual costs incurred by the utility, the shareholders will bear the difference between the actual and projected costs. Overall, we believe that for typical additions to plant, the respective burdens borne by, and benefits received by, shareholders and ratepayers balance out.

For our large energy utilities, small and routine additions to plant are projected in the general rate case or attrition adjustment based on historical experience. If the utility's actual additions are less than projected, ratepayers have overpaid; if the actual additions are greater than projected, ratepayers have underpaid. Again, although the process is not precise, we believe that these under- and overpayments balance out over time.

The alternative, less common treatment is accurate but imposes a somewhat heavier burden on the utility. When additions to plant are reviewed after they have been put in service, both the costs and the in-service date of the asset may be determined precisely. However, since rates must be set prospectively, the utility bears an added financial burden. Accrual of AFUDC must cease on the in-service date, but the cost of the plant will not be in rate base until the Commission has issued its decision in the case. Thus, during the time between the in-service date and the effective date of the rate or attrition case, the utility neither accrues AFUDC nor earns a return on its investment. Usually this treatment is employed for small assets that are expected to begin operation shortly before the start of the test year.

Neither of the two conventional treatments was suited for application to SONGS 2 and 3. Under the second approach, it would be unfair to expect the utility to bear the carrying costs of this enormous addition if the gap between the operation date and the start of the test year was of significant length.

But the first, anticipatory approach was also unsatisfactory for three reasons. First, the enormous costs of the SONGS project meant that the usual range of acceptable inaccuracy was not acceptable: even a 1% error in estimating the costs of the project would have a $45 million effect. Second, estimating the in-service date was extremely difficult. As late as mid-1982, for example, Edison was strongly urging the Commission to adopt a commercial operation date of August 15, 1982, nearly a year before actual operations began. If the Commission had followed Edison's suggestion, ratepayers would have been paying for a year for a plant that wasn't fully operating. Third, we were aware that the reasonableness review of these multi-billion-dollar plants would likely take a long time and could not be fit into the tight time limits of the general rate case.

Therefore, we created an unusual treatment for the SONGS 2 and 3 plants. We directed consideration of the reasonableness of the costs of the plants into a separate proceeding. We established criteria for determining when the plant was operating commercially. And we eventually established the MAAC account to record accruals of carrying costs during the time it will take to complete the prudency review.

The combination of these special steps and the actual history of SONGS 2 has created a situation that very much resembles the second type of treatment of new assets discussed previously. That is, the plant began commercial operation before the Commission had an opportunity to rule on the prudency of its costs, or in this case even to create the MAAC account. As when assets are reviewed for inclusion in rate base after they have begun to operate, the early operation of SONGS 2 raised two initial questions with rate implications: When must the utilities stop accruing AFUDC? When may the cost of the plant be placed in the MAAC account (the temporary surrogate for rate base treatment)?

The answer to the AFUDC question is derived from standard regulatory accounting practice. Accrual of AFUDC must cease when the plant begins commercial operation. For SONGS 2, commercial operation was deemed to begin when the plant met our COD criteria, on August 18. (All dates in this section will refer to 1983, unless indicated otherwise).

As Edison has pointed out, FERC accounting rules may require AFUDC accruals to stop on August 8. For purposes of state regulation, however, the commercial operation date is determined by application of our criteria. Edison's assertion that FERC accounting rules preempt conflicting state rules is erroneous. In fact, all of the cases cited by Edison as authority for its assertion clearly state that state regulatory authorities are not preempted by federal accounting rules. For example, in Northern States Power Company v. Federal Power Commission, 118 F.2d 141, 144 (7th Cir. 1941), the court held, "The system of accounting prescribed by the [Federal Power] Commission [FERC's predecessor] does not preclude accounting regulation by the state body....Each commission is empowered to act within its field."

The question of when the costs of SONGS 2 may properly be reflected in the MAAC account or in base rates is the narrow question of whether retroactive ratemaking occurred. After reviewing the briefs of the parties and the facts of our earlier actions, we conclude that in D.84-01-034 we violated Public Utilities Code §728 by authorizing the utilities to create a deferred debit account to record investment-related costs accrued from August 18 to September 7, and noninvestment-related costs from August 18 to October 8. Strictly speaking, the mere act of recording is permitted. However, these accruals were recorded for eventual, if partial, inclusion in rates. We conclude that these costs may not be reflected in rates under Section 728. Thus, the recording of these costs becomes an idle act.

Our conclusion stems from the simple principle of Section 728 that the Commission may set rates only prospectively. Until September 7, we had neither reviewed the plant's investment-related costs for inclusion in rate base nor established the MAAC balancing account to reflect the carrying costs on the SONGS 2 and 3 investment. Although we have in the past made adjustments to existing balancing accounts to reflect events occurring before the adjustment order was issued, we cannot lawfully make such retroactive adjustments to an account that did not exist when the events took place. The decision of

September 7, then, was the first time that the Commission could take action with implications for ratemaking.

The retroactive effect is apparent from the wording of Ordering Paragraph 4 of D.83-09-007:

> 4. If the plant meets the COD criteria prior to the issuance of this decision, Edison and SDG&E are authorized to continue accruing Allowance for Funds Used During Construction for SONGS 2, capitalizing operating and maintenance expenses, and crediting any energy generated at avoided costs to the SONGS 2 work order until the MAAC rates are placed into effect. (Emphasis added.)

This paragraph was modified in D.84-01-034 to accrue these costs in a deferred debit account. We also noted in that same decision the need to determine whether retroactive ratemaking had inadvertently been authorized by these treatments.

It could be argued that Section 728 prohibits only the accruals in the deferred debit account before September 7. Based on the analysis in this case, we now conclude that the deferred debit account was erroneously created in contemplation of retroactive ratemaking. Therefore, the whole deferred debit account must be rejected. We cannot reject the portion of accrued before September 7 and retain the portion accrued after September 7. In addition, if the Commission were to order the recovery of the accruals after September 7 for this account, the Commission would put itself in a contradictory position. The accruals of O&M expenses in the deferred debit account would differ from the O&M expenses found reasonable in the same decision of September 7. We prefer to reject the entire deferred debit accounting because the purpose for creation of the account unlawfully contemplated retroactive ratemaking.

On September 7, we took several actions affecting rates. For investment-related costs, we established the MAAC account and set the initial Major Additions Adjustment Billing Factor (MAABF) rates. For noninvestment-related costs, we determined the reasonable level of expenses for 1983 and authorized rates (the Annual Major Additions Rate (AMAR)) designed to recover those reasonable expenses. Investment-related costs were accrued in a balancing account; noninvestment-related costs were not. This difference in treatment leads to different results once the deferred debit accounts are rejected.

The MAAC account could begin occurring an undercollection on the day it was created, even if the rates authorized to partially offset the undercollection did not take effect until October 8. For noninvestment-related costs, however, balancing account treatment was rejected and rates designed to recover reasonable costs were authorized. Those rates did not become effective until October 8, and the utilities' recovery of their noninvestment-related costs is limited to the rates collected from October 8 on.

Edison's argument that the Commission's action in establishing the deferred debit accounts was not ratemaking and thus not barred by the prohibition on retroactive ratemaking ignores the point of our action. As we have discussed, in setting up the deferred debit account, our clear intention was to record costs for inclusion in the MAAC account, and through the MAAC account for inclusion in rate base. If the prohibition applies to the ultimate accounting, it also should apply to the preliminary accounting.

One further point remains to be resolved. In D.82-09-104, 9 CPUC 2d 697 (1982), we specified the ECAC treatment for Edison for energy generated by SONGS 2 during its pre-release phase. We determined that for ECAC purposes ratepayers would pay for the power generated before the COD at Edison's avoided cost rate, and a corresponding credit would be made against the construction costs. Thus, the revenue attributed to SONGS' preliminary generation would be applied to reduce the eventual plant costs to be placed in rate base. A similar approach was used by SDG&E.

After August 18, however the plant was in commercial operation and AFUDC accruals ceased, as we have discussed. If generation after the COD is credited at the avoided cost rate and used to offset accruals to the AFUDC or CWIP accounts, the utility is essentially recovering none of its costs of production. We also have reservations about the propriety of using post-COD energy to reduce pre-COD costs. On the other hand, if the utilities receive avoided cost payments for post-COD SONGS generation without an offsetting reduction to the construction accounts, ratepayers will pay much more for the SONGS generation than for other utility-owned, commercially operating plants employing conventional technologies. Such plants usually recover their actual fuel and other variable costs in ECAC.

We resolve these concerns by determining that the utilities should recover their respective nuclear fuel costs, calculated in cents per KWh, for energy produced by SONGS 2 from August 18 on through the ECAC/AER mechanism. This is the ordinary treatment of a commercially operating plant.

We recognize that the utilities will not recover all of their costs for the period from August 18 to October 8 because of the bar on retroactive ratemaking. Because rates designed to recover reasonable noninvestment-related costs for SONGS 2 were not effective until October 8, any of these costs incurred before October 8 cannot be included in the utilities' recoveries. Similarly, depreciation expense incurred before September 7 will not be recovered, although for reserve purposes depreciation commenced on August 18.

Also, because of the unusual timing of events, the utilities will not recover a return on their investment in SONGS 2 from August 18 to September 7. On the other hand, the utilities will recover their nuclear fuel costs from August 18 on. The recovery of fuel costs will occur in the existing ECAC and AER accounts, and therefore is not barred by the retroactive ratemaking prohibition.

We have thus concluded that for state ratemaking purposes, August 18 is the COD. Up to that date, pre-operation treatment (including accrual of AFUDC, capitalizing O&M, payment of avoided cost prices for generation, and crediting of avoided costs against construction costs) is appropriate. After August 18, SONGS 2 was in service. Recovery of fuel and other variable costs in ECAC and AER may begin immediately on August 18. Recording of investment-related costs may begin on September 7, when the MAAC was created, even though the MAABF rates did not take effect until October 8. Recovery of noninvestment related costs may begin on October 8, when the AMAR took effect. We calculate the net effect of this accounting treatment, compared to the treatment originally ordered in D.83-09-007 and D.84-01-034, to be a reduction of the MAAC account balance of approximately $13 million for Edison and $3.6 million for SDG&E.

While this accounting treatment is not perfect, we believe that it is a vast improvement over our more conventional treatments, to the enormous benefit of both utilities and ratepayers. Under conventional approaches, for example, if we had accepted Edison's estimated COD of August 15, 1982, ratepayers would have paid a return on the investment in a plant that was not operating. And if we had waited until the attrition case following commercial operation to take action to reflect costs in rate base, Edison would have had to bear the carrying costs of its investment until January 1, 1984.

We should also point out that if we are inexact in our accounting treatment when new generating plants are placed into rate base, we are also inexact in removing plants that are not operating from rate base. SONGS 1, for example, did not operate for nearly three years, yet it remained in rate base. Similarly, PG&E's Humboldt plant was not operating for three years before we removed it from rate base. We point this out not to justify the imprecisions in our process, but to demonstrate that these imprecisions do not always disadvantage the utilities.

V. Alternative Ratemaking

A. General

In D.83-09-007, issued on September 7, 1983, the Commission ordered applicants and staff to analyze alternative ratemaking methods for SONGS 2 & 3. The Commission stated that the review of alternative methods should include: (1) trended original cost rate basing (TRB), (2) levelization and sinking fund depreciation, (3) units of production depreciation, (4) deferral mechanisms such as those proposed for the Shoreham nuclear generating station before the New York Public Service Commission, and (5) extended deferral with the MAAC balancing account.

In response to this directive, Edison presented seven witnesses and four rebuttal witnesses, SDG&E presented two witnesses and two rebuttal witnesses, and the staff four witnesses. The staff was not permitted to offer rebuttal testimony since the staff's exhibits on alternative ratemaking were not distributed until April 24, 1984 or weeks after applicant's comparable exhibits were distributed. Consequently, staff had ample opportunity to rebut applicant's exhibits and testimony in its exhibit. If staff had been required to distribute its exhibit on the same time schedule as applicants, it would have been reasonable to grant the staff's motion to file rebuttal testimony. We concur with the ALJ's ruling in denying the staff's motion to allow filing of rebuttal testimony.

Edison's investigation of alternative ratemaking methods consisted of the following:

Original Cost Depreciation Methods:

1. Straight-line depreciation ratemaking (conventional)
2. Sinking Fund depreciation.
3. Units of production depreciation.

Cost Deferral (Balancing Account) Methods:

1. Levelized sinking fund depreciation.
2. Extended MAAC balancing account phase-in.
3. Shoreham type phase-in.

Trended (Inflation Indexed) Rate Base Method

SDG&E's investigation of capital recovery methods were basically similar to Edison's, however, due to the differences in assumptions made, the results were not identical. The staff made a study of similar options including avoided costs rates. While advocating avoided cost rates as the long-term position the Commission should adopt for new plants constructed in the future, the staff does not recommend the adoption of avoided cost rates for SONGS 2 & 3 since it would represent an untimely change in the rules and would cause investors to lose part of their investment.

B. Edison's Position

1. General

Edison recommends that conventional ratemaking continue to be followed. However, should the Commission feel compelled to adopt an alternative ratemaking method, any of the original cost methods, such as the levelized sinking fund depreciation method or extended MAAC balancing account phase-in method could be implemented by the Commission within the framework of existing regulatory law and accounting requirements without loss of tax benefits. Edison argues that trended rate base (TRB) and avoided cost methods cannot and should not be implemented because of conflicts with regulatory law and accounting requirements and potential loss of tax benefits.

2. Legal Requirements and Policy Goals of Rate Regulation

Edison states in analyzing whether alternative ratemaking methods can or should be adopted by the Commission, it is necessary to begin with an analysis of the legal requirements and policy goals of rate regulation, and how the policies of rate regulation are and can be designed to achieve those goals within the framework of legal requirements. Ratemaking policy and methodological changes should only be made in ways that will protect the interests of all parties while providing for continuing adequate and reliable supply of electrical energy to ratepayers at the lowest practically achievable total cost.

Edison argues that regulatory law requires that rates must be "just and reasonable". Just and reasonable compensation under the standard of Federal Power Commission v Hope Natural Gas Co. (Hope) as defined by the Supreme Court of the United States requires that rates be set such that:

> "...there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."

Edison further argues that while Hope does not require a specific ratemaking method, the court specifically said "under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling. "It is not the theory but the impact of the rate order which counts." In Bluefield Waterworks and Improvement Co. v Public Service Commission (Bluefield), the court defined when the impact of the rate order must be measured:

> "Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable, and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment." (Emphasis Added.)

Edison argues that thus the basic legal standard to which rate regulation must adhere is to establish rates which provide revenue for both investment-related costs and noninvestment-related expenses of the public utility property at the time such property is being used to provide service to the public. Edison states that by putting the requirement in terms of "revenue", the court is clearly requiring that the rates produce cash flow to the company sufficient to provide for operating expenses and capital costs of the utility.

While the legal standard for rate regulation is flexible, Edison states that it does provide some constraints on the so-called "economic" choices of ratemaking alternatives discussed by the staff, in that it requires that the sufficiency of the rates established be measured by the revenue requirement of property dedicated to the public service. Thus, ratemaking methods, such as avoided cost ratemaking which makes no attempt to measure the sufficiency of rates against the costs to the utility associated with the property dedicated to the public service, but rely on value of the service do not necessarily meet the legally mandated requirements of rate regulation. When the value of service is greater than the cost to the utility, there is no legal problem; however, when the value of service is less than the cost to the utility associated with the property dedicated to the public service, and rates are set based on that value, those rates are claimed to be legally insufficient under the Hope and Bluefield standard and, therefore, according to Edison, would be confiscatory, unjust, and unreasonable.

3. Conventional Ratemaking is Working

Edison argues that present regulatory policies encouraged and have resulted in efficient resource planning and utilization and good utility management. As a result, the ratepayers have been and continue to receive adequate and reliable electric service.[1] Edison argues that present rate regulatory practices promote intertemporal equity and that rate shock has not occurred in the past.

1 D.82-06-020, June 2, 1982, in OII 89, Appendix A, p. v, "Californians have enjoyed extremely reliable electric service". (Appendix A of D.82-06-020 was a joint report of this Commission and the California Energy Commission.)

Edison disagrees with the staff's contention that conventional ratemaking has led to excessive utility reliance on a single technology and technically exotic, capital intensive, large unit size options. Edison states that it is a leader among utilities with respect to development of alternative and renewable energy options and a diversified resource base and that SONGS 2 & 3 and the nuclear option are a part of that diversified resource base. Such a diversified resource base reduces dependence on any single resource option, especially expensive sources of foreign oil, and promotes stability of electricity supply and prices.

Edison argues that the inaccuracy of a load forecast is not a reflection of imprudent management or regulatory dysfunction. Rather the test of prudent management is how well it performs in meeting goals in light of changing circumstances such as the flattening load growth. In the case of load growth the test is how plants in the planning stage are deferred or cancelled, and resource plans revised to reflect new forecasts. According to Edison, proof that the process is working lies in the fact that when SONGS 2 & 3 began commercial operation, Edison's reserve margin was within planning targets and there was no excess capacity on Edison's system. Without SONGS 2 & 3, Edison's reserve margin would now be below acceptable levels. Edison's management's ability to finance, construct, and bring SONGS 2 & 3 into commercial operation during a period of record inflation, high interest rates and unprecedented flattening of load growth while meeting target reserve margin criteria and continuing to supply adequate and reliable electric service to its electric customers is the test of prudent management and also proof that the regulatory process is working.

Within the goal of providing continued adequate electric service to ratepayers at the lowest practically achievable total cost is the further objective of spreading costs equitably among past, present, and future ratepayers or the goal of intertemporal equity. Edison contends that conventional ratemaking promotes this goal because of all the various ratemaking options it provides the most uniform pattern of revenue requirement over time. Edison finds fault with the staff's analysis of a single asset and its conclusion that conventional ratemaking with straight-line depreciation results in intertemporal inequity because of front loaded payment streams. Edison agrees that when you look at the investment-related cost streams stemming from a single asset one is going to find a decrease in investment-related revenue requirements over time. The problem with this type of analysis is that ratepayer rates are based on a net cost resulting from all of the company's assets and not just a single asset. These assets are at various points in their respective depreciation schedules. Thus, today's ratepayers benefit from hydro facilities, oil, and gas facilities which are nearly fully or substantially depreciated. Edison argues that if you look at the ratepayer impact from a systemwide or total company viewpoint, conventional ratemaking does not produce intertemporal inequity.

Edison further argues that rate shock as that term has been applied in other jurisdictions has been where a large nuclear plant has been added by relatively small utilities requiring an increase in rates of 50% or more, thereby making some form of phase-in necessary. In the case of SONGS 2 & 3 a rate increase of only 12 percent would be required using conventional ratemaking, of which four percent has already been implemented leaving only an increase of eight percent necessary.[2] Rate increases of this magnitude do not constitute rate shock, nor are rate increases of this magnitude large by historical standards for Edison.

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2 Edison in the September 13, 1983 oral argument modified its requested increase in Phase 1B from $368 million to $300 million or an increase of approximately 6½%. This was attributed to a combination of a reduction in revenue requirement in 1985 due to accrued depreciation, and an increase in the level of sales.

4. Alternative Ratemaking Methods Investigated

a. General

Edison, SDG&E, and staff all submitted analyses of alternative ratemaking. Although there were differences in some of the assumptions used, they were generally similar. The following discussion of Edison's analyses of various ratemaking methods would generally be true for the analyses made by SDG&E and staff except for the staff's use of sinking fund depreciation in its TRB proposal and SDG&E's constant revenues or annual 2% increase over time assumptionsin its TRB analysis.

b. Original Cost Depreciation Methods

The three original cost methods analyzed were straight-line depreciation (SLD), sinking fund depreciation and units of production depreciation. Under straight-line, the method currently used by the Commission, depreciation is spread equally to each accounting period over the useful life of the asset with the utility given the opportunity to earn an authorized return on the undepreciated investment. SLD provides the most uniform pattern of revenue requirements over times as the decline in investment-related revenue requirements is offset by increases in operations and maintenance (O&M) expenses.[3] Under sinking fund depreciation ratemaking a depreciation schedule that increases over time is used, resulting in investment recovery (depreciation and return) which is approximately level. This method, however, does not appropriately reflect the loss of service value of the asset. This represents a potential burden on future customers since a change in depreciation would have a much greater impact on future rates than under SLD. The units of production method attempts to match depreciation expense with the level of energy produced. Depending upon the relationship between production actually experienced to production expected under the straight-line original cost method, the units of production method of depreciation will produce depreciation expense that varies from straight-line.

3 Staff analyses excluded O&M expenses.

c. Cost Deferral (Balancing Account) Methods

Cost deferral methods do not vary basic ratemaking and accounting principles, but rather establish an arbitrary deferral of investment-related revenue requirement through the use of a balancing account. The three cost deferral methods investigated by Edison were the levelized sinking fund depreciation, extended MAAC balancing account phase-in and Shoreham type phase-in.

Due to tax normalization and reserves for decommissioning, the sinking fund depreciation method does not result in a level investment-related revenue requirement over time. Under the levelized sinking fund method, these are taken into account together with a balancing account in an attempt to levelize investment-related revenue requirements. In practice, it is unlikely that this approach would result in a level investment-related revenue requirement over time because the calculated levelized revenue requirement is based on a forecast of rates of return over the asset service life and the realized actual rate of return would vary.

The extension of the MAAC balancing account which would permit recovery of investment-related revenue requirement is another possibility. Edison modeled a two-year phase-in with a recovery over a five-year phase-out period. This would result in a relatively gradual series of rate increases in the phase-in period while limiting the size of the balancing account to about $500 million.

The Shoreham phase-in plan would not be applicable to SONGS 2 & 3 since Shoreham provides for a reversal of Construction Work in Progress (CWIP) benefits. Since CWIP benefits were not made available in California prior to commercial operation, this method would not be applicable. SDG&E modeled a Shoreham type method assuming an initial seven percent increase, followed by seven percent annual increases over five years and straight-line capital recovery over the remaining life of the asset.

d. Trended Rate Base Method

Under trended rate base ratemaking (TRB), the value of an asset is increased over time to reflect the increases in replacement value resulting from inflation. The increases in asset value is offset by a reduction in current cash return on the asset value. TRB divides the authorized nominal rate of return into two components, a real rate of return and a rate of return to compensate for inflation. The utility's current cash return is based on the real rate of return while the inflation portion is reflected as a write-up of rate base. Under TRB, revenue requirement is lower than SLD initially and then rises at approximately the rate of inflation over the service life of the asset. In the last year of the service life, revenue requirement is projected to be 6 to 8 times the first year's revenue requirement.

Edison argues that since TRB method does not afford the utility an opportunity to earn its authorized rate of return on the asset dedicated to public service at the time it is providing the service, it does not meet the minimum requirements of regulatory law. Furthermore, under TRB the asset value rises over the first two thirds of the asset service life, requiring recovery of about $5 billion of plant investment over the latter third of the asset life. This places a substantial risk on future ratepayers who must pay for recovery in rates of this $5 billion of plant investment at the time the plant is in the later stages of its service life, and where operations may be reduced due to the presence of new generating resources, technical changes, higher O&M expenses, and the anticipation of retirement of the facility.

e. Avoided Cost

The final ratemaking option, avoided cost ratemaking is a service value method of ratemaking. The cost of the plant would not be included in rate base nor would the expenses related to the operation of the plant be included in the computation of revenue requirement. Instead, the utility would receive revenue as if the energy was purchased on a long-term contract. Under staff's avoided cost ratemaking model, revenue requirement would rise from $349 million in 1984 to $781 million over the life of the asset in 1984 dollars. Compared to SLD or TRB, the avoided cost payments are greater than both methods after 1994. Further, Edison contends that avoided cost rates do not necessarily meet the basic legal criteria of providing sufficient revenue to provide for both the investment-related and noninvestment-related costs of the property devoted to public service.

5. Problems With Staff Analysis

a. TRB and Legal Requirements

Edison alleges that TRB does not meet the minimum legal requirements of rate regulation because the company would not be provided the opportunity to earn its authorized rate of return on the asset at the time the asset is being used to provide service to the public. Edison states that staff developed a real weighted net cost of capital of 6.05% for 1985 in Exhibit 35. Under TRB, the company would earn a cash return on the trended asset at this rate (the cash rate of return). The weighted nominal cost of debt and equity is 5.44 percent leaving a 0.61 percent cash rate of return for the common equity component. Edison argues that by any reasonable standard a 0.61% rate of return on common equity available for the payment of dividends is grossly insufficient. Edison faults staff's contention that the measure of the adequacy of the return on common equity must be made with reference to the total cash revenues of the company. The staff logic is flawed according to Edison, since Edison is entitled to earn its authorized return on all its assets and also because the staff's logic would result in a subsidy by other assets on the trended asset.

b. Avoided Cost Method and Legal Requirements

Edison argues that staff's avoided cost proposal fails to recognize the minimum legal requirements of rate regulation, because there is no test of the sufficiency of the rates to meet the revenue requirement of the asset dedicated to the public service. Furthermore, avoided cost rates expose ratepayers and investors to both windfall losses and gains. Under avoided cost ratemaking relatively inexpensive resources such as hydro would produce windfall gains to investors and corresponding losses to ratepayers. SONGS 2 & 3 could also produce windfall gains to investors. Using the staff valuation method and substituting Commission-approved capacity values and using staff's utility discount rate would produce a net economic gain of $72.3 million in present worth dollars according to Edison. If the ratepayer discount rate of 10 percent is used, the economic gain would be a significantly higher figure of approximately $1.7 billion. Thus, the $1.5 billion economic loss alleged by the staff can become an economic gain by changes in two factors.

c. Faults in Staff Economic Analysis

Edison argues that use of avoided cost as a standard of reference from which to judge the efficiency of TRB raises the question as to which avoided cost to use since Edison has several approved standard offers. The staff avoided cost calculation excludes capacity value through the mid-1990's based on the assumption that SONGS 2 & 3 has no value until then. Edison also faults staff's assertion that rates which are level in real terms are efficient and equitable, while conventional rates which are front loaded and decline in real terms over time are inefficient and inequitable. Such assertion is faulty, inconsistent both with economic theory and empirical evidence, and inconsistent with staff's own definition of equity according to Edison.

Edison states that staff's TRB proposal is based on the concept of economic depreciation, that is depreciation which considers both the remaining life of the asset and its current value. This allows rate base to increase in nominal terms in the early periods. However, in a competitive industry, economic depreciation is simply the real change in price of an asset over time, where price is determined by the expected future stream of net cash flow from the asset. As expectations of future net cash receipts change, economic depreciation will reflect windfall gains and losses. Application of the concept of economic depreciation however creates circularity problems since economic depreciation patterns would depend on the prices of electricity which are thereby set. This circularity problem does not exist in the competitive market because the intertemporal price path is set by many individuals and firms. The economic models used by both Edison and the staff have simplifying assumptions to make comparative analysis possible, however, they are not representative of capital assets in the real world. The economic depreciation assumptions which underly the staff TRB proposal conflict with empirical studies of competitive industries. Furthermore, there is no basis for believing that the pattern of rates which results from TRB ratemaking would be economically efficient, or by comparison, that conventional ratemaking is front loaded in comparison with prices (rates) in a competitive market.

Staff tries to support the pattern of rates which results from TRB by arguing that level or slightly increasing rates are equitable to ratepayers. However, Edison contends that this is inconsistent with basic principles of regulation that rates must provide for the investment-related and noninvestment-related costs and expenses at the time an asset is used to provide service. Edison further argues that there is no a priori reason why rates should be level in real terms. If a particular pattern of economic depreciation suggests that for economic efficiency, rates ought to decline over time, then economic theory suggests that rates should decline over time.

d. Staff's Calculation of Value of SONGS 2 & 3 is Faulty

Edison argues that staff's present worth analysis in choosing between alternative ratemaking methods has little value. Edison states that the staff asserts that the ratepayer discount rate is greater than the utility rate of return. If this were true, ratepayers would arguably prefer a ratemaking method that defers all revenues until the end of the asset life resulting in a gross subsidy of present ratepayers by future ratepayers. Conversely, if the ratepayer discount is less than the utility rate of return, one would conclude from a present worth analysis that ratepayers would prefer a ratemaking method that places all revenues at the beginning of the asset's life.

Edison argues that staff's present worth analysis is methodologically faulty because it substantially understates the value of SONGS 2 & 3 by arbitrarily failing to allocate any capacity value to SONGS 2 & 3 until 1994 and used an inappropriately high discount rate to substantially understate the value of future costs, thereby skewing the overall result of the present value analysis downward. Edison believes that the 12 percent reserve margin used by the staff is arbitrary and without any reasonable basis compared to the reserve margin criteria used by the Commission in past proceedings, which are 1.5 times to 2 times greater than the value used by the staff. Edison also argues that the 17 percent discount rate used by the staff is inappropriate and unreasonably high since it is based entirely on an investor's viewpoint and not on a ratepayer's viewpoint. Edison's witness, Dr. Roll, testified that the ratepayers paying for San Onofre are not confronted with an investment problem, but a question of how much ratepayers should pay now to avoid having to pay an uncertain amount in the future (an insurance problem). The fundamental difference is that the ratepayer has a cash outflow, either now or in the future, while an investor has a cash outflow now and a cash inflow in the future. Assuming the continuation of regulation, the ratepayer has the obligation to make a payment either now or in the future, whereas the investor can avoid the transaction entirely. These fundamental differences are very important to the choice of an appropriate discount rate according to Dr. Roll. The use of a discount rate appropriate for an investment problem leads to nonsensical conclusions when applied to a ratepayer situation.

Dr. Roll testified that the appropriate discount rate for the ratepayer problem is less than the risk-free rate. He stated that the yields on long-term government bonds are the best proxy of a long-term risk-free rate available and would represent the maximum discount rate that would be appropriate for the ratepayer situation. Under current market conditions, Dr. Roll concluded that a 10 percent nominal rate is the upper band.

As we discussed earlier, Edison states that by using the same staff method which produces a $1.5 billion economic loss to ratepayers from the operation of SONGS 2 & 3 and substituting an appropriate capacity value and the use of a 10 percent ratepayer discount rate, the net economic loss would be converted to an economic benefit to ratepayers of $1.7 billion.

6. <u>Criteria for the Selection of a Ratemaking Method</u>

a. <u>General</u>

Edison believes the fundamental criteria in the selection of a ratemaking method within the framework of regulatory law should be to provide for a continued adequate and reliable supply of electrical energy at the lowest practically achievable total cost to the ratepayer. This requires an analysis of the effect of the ratemaking action on future costs, principally the utility's cost of capital. The ratemaking action must provide the utility with an opportunity to maintain its financial integrity, credit standing, and ability to attract capital. If the investor perceives that a Commission action tends to increase the level of risk of an investment, the future cost of capital will increase. Edison perceives that adoption of TRB will have a substantial effect on the future cost of capital.

Current investors invested their money in Edison with the expectation of receiving conventional ratemaking treatment for SONGS 2 & 3. There was no prior indication from the Commission that there would be any deviation from conventional ratemaking either prior to or during the extended construction period. While investors do not expect static regulation, TRB would be a major regulatory change applied on an after-the-fact-basis. Investors are now uncertain as to when the investment in SONGS 2 & 3 will be included in rate base and allowed to earn a full cash return. Should the rule be changed now, investors will perceive a substantial likelihood that the rules could be changed again when the deferred revenues become due. Edison further argues that bond ratings cannot be maintained indefinitely on expectations alone and that Moody's and Standard and Poor's are waiting to evaluate the Commission's decision in this proceeding.

In addition, investors perceive a greater regulatory risk for Edison as a result of the MAAC proceedings which resulted in the adoption of a TCP, the deferral of revenues, and the consideration of alternative ratemaking. Investors also perceive an increase in risk due to asset concentration. Under conventional ratemaking, the level of asset concentration declines rapidly. However, under TRB, SONGS 2 & 3 would continue to represent a major portion of Edison's assets for the first 20 years of their lives. Thus, investors would perceive the continuation of a high level of asset concentration as an increase in risk.

Edison states that for a long time, it has been able to maintain its double A bond rating because the rating agencies and investors have been expecting a substantial improvement in Edison's financial condition once SONGS 2 & 3 become operational. Adoption of TRB does not provide the substantial improvement in cash flow necessary for Edison to maintain its AA ratings, therefore, such ratemaking treatment jeopardizes the company's credit rating and ultimately cause higher costs to ratepayers. Based on the staff's analysis, the cash after tax interest coverage is projected to average 1.83 times for the 1984-88 period. This is a negligible improvement relative to the 1.79 times coverage maintained during the extremely difficult period of 1978-82. Edison further argues that even if you assume for the sake of argument that the averages for the 1978-82 period for the staff's group of double A utilities are reasonable proxies for levels required by rating agencies under TRB, Edison's cash interest coverage, and quality of earnings will not be adequate to maintain a double A bond rating. The following table shows Edison's recorded ratios for 1978-82, projected ratios for 1984-88 under TRB compared to recorded ratios for AA rated utilities for 1978-82.

	EDISON		AA Rated Utilities
Ratio	Recorded 1978-1982	Projected 1984-1988	Recorded 1978-1982
Quality of Earnings	47.8%	51.2%	74.0%
Cash Interest Coverage			
After-Tax	1.79x	1.83x	2.16x
Before-Tax	2.05x	2.71x	3.13x
Internal Cash Generation	24.2%	41.6%	-

The loss of Edison's double A rating could result in the long run in an annual increase in revenue requirement of approximately $20.2 million for the debt component without considering the impact of TRB on common equity. Edison further claims that the cost of common equity, considering only the increase in exposure to inflation and interest rate risk, will increase by 76 basis points or an increase in the net present value of future costs to ratepayers of approximately $545 million. Edison contends that the staff totally ignored the impact of this cost in its analysis.

Edison argues that the staff's analysis and conclusions that TRB would keep investors whole is inappropriate since it relies on projected financial ratios which, in and of themselves, cannot be used as a basis for concluding that present investors will not be affected by TRB and that the cost of capital will not be substantially increased. Investors and rating agencies are concerned with the prospective financial health of Edison and will look at financial ratios, however, their conclusions will be based on their judgement, expectations, and general perceptions together with the financial ratios.

Edison further states that the financial ratios staff focuses on are inappropriate for the following reasons:

1. Staff reports total earnings for common equity rather than return on common equity or earnings per share.

2. Staff includes the asset write-up in the reported earnings, which Edison contends cannot be included in reported earnings.

3. Investors are interested in cash flow and cash coverage ratios. Although staff's calculation of projected cash after-tax interest coverage for the period 1984-88 will average only 1.83 times or a slight increase from the 1.79 coverage for the 1978-82 period, staff claims that there will be an immediate and significant improvement.

4. Staff compares its projected financial ratios to Edison's historical ratios and the historical ratios of a group of double A companies. Comparison of ratio to depressed historical ratios is inappropriate.

Edison argues that investors will not be made whole under TRB as contended by the staff because:

1. If TRB is adopted, the market value of Edison's common equity is estimated to decline by about $59 million and the market value of Edison's bonds and preferred stock outstanding would decline by about $18 million.

2. Under TRB, staff proposes to use an estimated rate of inflation for return and recorded inflation for asset write-up. When the expected inflation included in long-term securities rates and recorded inflation on a monthly basis may not and, in all probability, will not be the same either Edison's investors or ratepayers will be harmed. Use of a true-up mechanism to

account for this difference does not solve this problem, since financings are made at rates which incorporate the expected inflation. True-up of one half of the equation, the asset-write-up side does not true-up the whole equation.

3. In deflationary times, TRB may exacerbate intertemporal equity problems. Under deflation, staff would write-down the value of the asset and if the asset is written down below the original cost less the realized cash depreciation, the company's property is being directly confiscated.

b. Implementation Issues

Edison states that any ratemaking method to be adopted should be capable of practical implementation in the context of accounting requirements, tax laws, and rate regulatory practices. There are a number of complex accounting issues related to deferred cost recovery plans, and most specifically to the TRB method. Adoption of TRB method would result in the company being required to maintain accounting records and financial statements that would not incorporate or reflect the ratemaking treatment given to SONGS 2 & 3. This would result in a deterioration of the company's financial position and reported results of operation with a qualified or adverse auditor's opinion almost certain to follow.

Asset write-up as required under TRB is prohibited by Generally Accepted Accounting Principles (GAAP). Edison also argues that since asset write-up is not an incurred cost as defined in FASB 71, it is against GAAP to capitalize such amounts on the books of account. Edison acknowledges this Commission's sovereignty over the establishment of retail rates within this Commission's jurisdiction, however, it argues that case law has consistently supported the principle that accounting requirements prescribed by state regulatory commission are subordinate to FERC accounting requirements. Since FERC accounting requirements prevail, Edison argues that the company must adhere to FERC accounting requirements which require that plant be recorded at original cost and precludes the asset write-up under TRB.

Edison further argues that before any cost can be deferred to future periods a high level assurance of future recovery is necessary. Disregarding other problems relating to TRB, the inherent characteristic of TRB imposes serious uncertainties as to whether a sufficiently high level of assurance of future recoverability could possibly be provided by a rate order of any regulatory commission. The simple fact that this would require assuring recovery of 30 years into the future and the fact that the present Commission cannot irrevocably bind actions of subsequent Commissions would indicate that a rate order providing the level of assurance of recoverability over the term of the TRB asset is virtually impossible.

The staff's TRB proposal uses sinking fund depreciation to recover the original cost of the asset using the cash rate of return as the sinking fund interest factor. Sinking fund depreciation facilitates the phase-in to the extent that the reduction in depreciation expense exceeds the increase in return on investment which results from a larger rate base. Edison argues that the sinking fund method does not distribute the costs equitably or pro rata to the level of service provided, and is not equitable to ratepayers during the later years of the service life of SONGS 2 & 3.

Edison also finds that TRB creates tax problems with respect to accelerated cost recovery system (ACRS) depreciation and investment tax credit (ITC). The concept of asset write-up under TRB presents problems in defining an appropriate method for normalizing the difference between book depreciation applied to tax basis and ACRS tax depreciation. The difficulty is in identifying the book depreciation rate to be applied to the tax basis because book depreciation includes recovery of both original book cost and asset write-up. Since the asset write-up under TRB is greater than depreciation in the early years, the IRS could take the view that there is no depreciation of the book asset until later in the asset life when the book value becomes less than original cost.

In addition, there are many possible interpretations relating to the normalization computation for the TRB depreciation. Edison's tax witness presented the following three possible computational methods: positive book/tax, zero book/tax, and negative book/tax normalization. The witnesses testified that while there is substantial uncertainty as to what approach the IRS may take, the negative book/tax normalization method is the method most likely to be found acceptable. The negative book tax method results in the largest amount of deferred taxes thereby partially negating the intended benefit of alternative ratemaking. The staff calculations used an equivalent of the positive book tax method which Edison believes is the method least likely to be found acceptable by the IRS.

Edison's witnesses testified that there was substantial uncertainty as to which, if any normalization method under TRB would be acceptable to the IRS and strongly recommend that should the Commission be seriously considering adoption of TRB, it afford the company the opportunity to obtain a ruling on appropriate tax normalization from the IRS. Edison also points out that since TRB method results in a reduction in taxable revenue, it is likely to attract the attention of the IRS. In the case of ITC, Edison sees similar problems with the IRS. Should the IRS take the position that depreciation of the asset does not begin until the inflated book basis of the asset is amortized below its original cost and therefore not permit ratable flow through of the ITC, the tax effect would partially negate the intended result of the alternative ratemaking method.

Edison contends that the staff's treatment of the tax problem is cavalier because the penalties associated with failure to comply with tax normalization requirements are severe. If the IRS determines that the company was in violation of the ACRS requirements, Edison would not be eligible for ACRS depreciation deductions. Furthermore, should it be determined that the company was in violation of the ITC ratable flow through requirements, the IRS code states that no ITC shall be allowed with respect to any public utility property. At a minimum, this would result in a disallowance of all ITC claimed for SONGS 2 & 3 since the start of construction or approximately $185 million. A broader interpretation could mean the disallowance of all ITC claimed on all public utility property for all open tax years, which could range from $40 million to $80 million for every year affected.

Edison sees additional ratemaking and regulatory problems associated with TRB because of the complexity and difficulty involved in administering TRB. The burdens include:

1. The necessity of authorizing non-cost based rate increases when no new asset has been added to rate base, in the magnitude of $400 million of rate increases for five consecutive rate cases.
2. The necessity of determining and applying a "real" rate of return in the course of normal rate case proceedings, when in practice neither the real rate of return nor the expected inflation premium are observable or measurable.
3. The necessity of determining and applying the appropriate inflation index to regularly write-up the value of utility assets is not simple and the application of the concept is imprecise and can produce widely varying and perhaps unfair and unjust results.
4. The necessity of establishing and maintaining a true-up mechanism to account for differences in forecast and realized levels of the write-up index. The need to audit such a balancing account and the necessary rate case preparation and hearing time necessary to deal with balancing account amortization over the life of the asset is another example of the procedural and administrative complexities associated with TRB.

C. SDG&E's Position

1. General

SDG&E investigated the straight-line capital recovery, units of production capital recovery, sinking fund capital recovery, "Shoreham-type capital recovery, trended original cost capital recovery methods and the balancing account mechanism. After reviewing the revenue requirements and capital recovery stream under the various capital recovery methods investigated, SDG&E adopted the following position:

a. SDG&E strongly supports continuing the use of straight line depreciation. All of the other methods considered with the exception of the unit of production and balancing account methods, arbitrarily alter depreciation to produce a desired revenue requirement, and that depreciation no longer accurately reflects true economic depreciation of the asset. SDG&E believes this is inappropriate.

b. SDG&E believes that the magnitude of the rate increases associated with the SONGS 2 & 3 is not sufficiently large to warrant deviation from traditional ratemaking practice.

c. Finally, if this Commission is determined to authorize revenue increases that are less than the true cost, it should arrive at those revenue increases without adjusting depreciation schedules.

2. Total Ratemaking

SDG&E believes that if you consider the ratemaking for SONGS 2 & 3 as only part of a total ratemaking picture, it is clear that the Commission's concern regarding rate stabilization and intertemporal equity are best satisfied by the continued use of traditional ratemaking. While such an approach does result in a rate increase of eight to twelve percent, such increase is clearly far short of a rate shock by any accepted definition of that term. In addition, the intergenerational equities among ratepayers, as well as equity consideration of investors, are best served by minimizing rates through continuity of long-term ratemaking. With regard to the argument of subsidies from one generation to another, SDG&E argues that to the extent such subsidies exist, each generation of ratepayers is subsidized by the prior generation. As a trade-off for this minimum subsidization, all risks due to uncertainty in other expense categories and in forecasts necessarily flow to future ratepayers. In such a total ratemaking context, the equity interests of both ratepayers and investors are best served by continuity of ratemaking with each generation of ratepayers receiving the same treatment as prior and subsequent generations.

SDG&E argues that the Commission should look on ratemaking for SONGS 2 & 3 as part of a total ratemaking package rather than from a single project viewpoint. SDG&E and Edison have incorporated O&M expenses in its analysis which even under conservative inflation assumptions will rise each year. Under conventional ratemaking, an initial increase in rates will be required, however, in subsequent years non-fuel revenue requirements will go down despite rising O&M expenses. On the other hand, under the staff's TRB proposal, the Commission will be confronted with increasing revenue requirements every year over the 30-year life of the plant. In addition, the Commission will further be confronted with additional increases for the inevitable increases in O&M expenses related to these facilities. By adopting TRB, the Commission will be institutionalizing inflation and handcuff the Commission's future flexibility.

SDG&E's witness Robert Hahne, a partner with Deloitte, Haskins & Sells, testified that in an increasing cost economy it makes no sense to defer costs for future recovery when we already anticipate future costs will be higher even before the recovery of these deferrals are considered. Therefore, the witness does not support proposals which fail to recover cost and return in the proper period and burden future Commission decisions. SDG&E states that it does not make sense to abandon traditional rate regulation to gain a short-term rate reduction for the first seven years and increasingly higher rates over the remaining 23 years under TRB.

SDG&E concurs with Edison that the rate increase required under traditional ratemaking of eight and twelve percent respectively for Edison[4] and SDG&E do not constitute rate shock. In the context of overall rate levels, SDG&E states that in the case of Edison, an eight percent increase will only increase electric rates to the level of two years ago. In the case of SDG&E inclusion of SONGS 2 & 3, Southwest Powerlink and the CAM decrease would have an impact on an average electric and gas customer bill of a one percent increase over rates in effect at the beginning of the year.

3. Intertemporal Equity

SDG&E states that there are two definitions of equity presented in these proceedings. The staff's definition is "Ratemaking options that yield revenue streams over their life similar to the avoided cost are equitable among ratepayers, and others are inequitable to the extent that they deviate from this pattern..." Edison's definition is "In my mind intertemporal equity is that the customers are being treated equally over a continuum of time and over a period when various rates are in effect". SDG&E's witness further added "In my opinion, it is certainly not fair or equitable, if we are addressing intergenerational fairness of rates, to look at only one segment of cost and ignore the lessons of experience that tell us other costs of future operations more than offset the gradual reduction in investment".

4 Edison reduced its requested increase to 6½ percent at the oral argument on September 13, 1984. See footnote 2.

SDG&E states that there are numerous problems in utilizing an avoided cost standard for judgements on equity as testified to by Dr. Jurewitz, economist for Edison. The problems are:

1. Revenue recovery based on avoided cost would either under-collect or over-collect relative to costs actually incurred;
2. Development of cheap, infra-marginal resources would cause windfall gains to utilities. One of the desirable characteristics of present regulation is to capture such economic rents for ratepayers in the form of lower rates;
3. Shortage or surplus conditions in the market result in windfall gains and losses for utility shareholders and ratepayers alike; and
4. Returns under an avoided cost concept are necessarily riskier, thus requiring higher rates of return to the investor.

SDG&E argues that it can hardly see how it would be fair or equitable to let ratepayers enjoy the service benefits of a plant for 19 years or so under TRB ratemaking and not contribute so much as a nickel toward its costs; in fact, to pay rates less than the current cost of capital, consigning to later generations of ratepayers payment not only for the entire cost of the plant, but even payment for a portion of the cost of capital in the earlier decades. Such a pattern for return of capital shows absolutely no matching of the costs of the plant with those who benefit from the use of the plant.

4. <u>Financial Effects of TRB</u>

SDG&E challenges the staff's contention that TRB will keep utility investors whole as being inaccurate. Under TRB, instead of the expected cash earnings under conventional ratemaking, when the plant goes into service there will be a new form of noncash earnings with a Commission's promise to pay back in cash some 20 years or more in the future. This change in cash flow affects the costs and risk to investors even if there is virtual certainty that the future cash flows will be paid. Furthermore, interest and dividend payments cannot be paid out of deferred earnings. Under TRB, as proposed by the staff, the entire deferred revenue or asset appreciation flows through to the common stockholder, although the rate of return on which it is calculated applies to a balanced financing portfolio of the utility. In the early years, the common stock dividends must be paid out of real cash earnings from other assets receiving conventional rate treatment, depreciation or deferred taxes. SDG&E argues that payments out of any of these sources of cash hardly indicate that the investor is being made whole on the SONGS portion of this investment in the utility.

SDG&E states that the staff acknowledges that investors also face the risk of future regulatory actions. The first risk is that the Commission will effectively take away a portion of the deferred cash return when it comes due and the plant is still fully and effectively operational. The second risk is what the Commission will do if the plant does not perform for its full expected life. Should this occur in the 20th year, the Commission will be faced with a rate base decision of some $916 million under TRB, as opposed to a rate base decision of $216 million under conventional ratemaking for SDG&E's investment in SONGS 2 & 3. Facing a capital write-off decision of four times the magnitude under TRB, investors would be concerned that the Commission might adopt some expediency, such as concluding that full return of the deferred asset write-up was conditional upon the asset performing for its full economic life.

5. Flaw's in Staff Analysis

SDG&E argues that the initial error in the staff analysis is the equating of public interest with economic efficiency. Staff defines economic efficiency as resulting from organizing consumption and production so that total value or benefit received in the long run by society is as great as it can be. SDG&E's economist, Dr. Schiffman, states that economic efficiency has nothing to do with any definition or reference to benefits realized in the long run by society, and that measures of society's welfare are nothing but

formalized value judgements on the part of the economists.
Dr. Schiffman proceeded to explain that a state in an economy where one person has all the goods and services is, strictly speaking, an efficient state, however, no one would judge that state to be one which maximizes society's welfare. Therefore, Dr. Schiffman concludes that matters of intergenerational equity are institutional judgement factors, not economic factors, and that traditional capital cost recoveries meet the requirements of economic efficiency.

SDG&E also argues that the exigencies and advantages of a particular time have led either ratepayer groups or utilities to propose changes from traditional ratemaking concepts when such changes appeared to be advantageous to the proposer at the time. SDG&E notes that the Commission has consistently declined to make such changes and has continued to adhere to its policy of setting electric rates on historical costs less depreciation basis.

One of the advantages claimed by staff for TRB is that it cuts ratepayer losses to half of what it would suffer under conventional ratemaking. SDG&E argues that this savings is not due to any magic of TRB, but rather is due to the deferral of payments, and the staff's assumption that the investor's discount rate is higher than the cost of capital. If the opposite were true, ratepayers would favor paying off earlier. Thus, the entire savings to ratepayers from TRB is contingent on the relationship between how much the ratepayer has to pay to defer payment and the rate utilized to discount the various streams of ratepayer payments.

SDG&E argues that the staff's use of an investor discount factor is incorrect since ratepayers are not making an investment decision but rather an insurance decision; that is, how much to pay now versus paying later. Under such an insurance situation, SDG&E agrees with Dr. Roll's testimony that the risk free rate of interest is the appropriate rate to be used. Using such a risk free rate, the $750 million savings for ratepayers claimed by the staff under TRB will become an almost billion dollar increase when the income streams were discounted at the proper ratepayer discount rate.

SDG&E states that the staff failed to recognize the risk premium required by the deferral of ratepayer costs under TRB. Edison's witness, Dr. Roll, testified that if TRB were adopted for SONGS 2 & 3, it would cause an increase in the net present value of future rates of at least $545 million and if applied to all future investments, an increase in the net present value of future rates of $1.5 billion. SDG&E concludes that the staff analysis was flawed in numerous ways and taken in total, the impact of the errors and omissions is a reversal of the alleged economic superiority of trended rate base over conventional ratemaking.

6. TRB Implementation Issues

SDG&E states that the staff's TRB proposal is inconsistent with GAAP, and FERC uniform system of accounts for electric utilities and, therefore, not acceptable for inclusion in published financial reports of the company. The staff's TRB proposal further reverses the Commission's long time policy of utilizing straight-line depreciation by using sinking fund depreciation, a policy abandoned by this Commission in 1950's as well as by other regulatory bodies. SDG&E also expressed the same reservations about TRB and FASB 71 expressed by Edison. Similarly, SDG&E also expressed concerns about the tax consequences of adoption of TRB. Due to California's history on normalization, SDG&E cautions the Commission that the IRS will look with question at any new, novel or unconventional rate-setting method coming out of California, and the tax implications of such ratemaking method.

Since there are no guidance to aid in the application of mandated normalization to the TRB method, SDG&E points out that witnesses Reender and Dacek of Edison, both recommended that advance rulings be obtained from the IRS regarding the normalization of ACRS tax benefits and rateable flow through of ITC. These may take a year and a half to two years to obtain resulting in a substantial delay in any final implementation of TRB. Failure to normalize the ACRS benefits properly would result in the loss of ACRS on the SONGS property and failure to properly flow through the ITC properly would result in an even greater penalty, since it could result in the loss of all jurisdictional investment tax credits.

Should TRB be adopted, it will be necessary to hold additional hearing for adoption of an inflation index, and determination of the additional risk premium necessary. TRB also will add to the complexity of general rate case proceedings because it would require two classes of assets, the return on each set of assets would have to be considered separately, and finally, the Commission would not only have to adopt a nominal rate of return, but also a real rate of return. TRB also will require the establishment of another balancing account in order to true-up the cash return on the estimated appreciation on rate base due to inflation which was established in a general rate case and the actual rate base increases from recorded inflation. The true-up process will have to be done in an ECAC rate proceeding, thus, further complicating the ECAC process as well.

SDG&E concludes that of the three ratemaking options recommended in this proceeding, conventional ratemaking is clearly in the long run interest of both utility ratepayers and investors. The second best option would be a limited term phase-in under the MAAC balancing account should the Commission decide that some form of alternative was necessary. TRB would clearly be inferior.

D. City of San Diego's Position (City)

City takes the position that under normal circumstances, it would agree with the utilities that conventional ratemaking should apply to the completed SONGS units, however, SONGS 2 & 3 do not present a case of normal circumstances for the following reasons:

1. The completed cost of the plant exceeded the estimated cost when the plant was first certificated by over ten-fold. While reasonableness will be considered in Phase 2, ratepayers should not be saddled for cost overruns.

2. Ratepayers should not be saddled with the utilities' over-estimate of load growth. When SONGS 2 & 3 began construction peak load forecasts for 1983 were 16,440 MWe for Edison and 3,150 MWe for SDG&E, actual peaks for 1983 were 13,464 MWe for Edison and 2,068 MWe for SDG&E.

3. The utilities projected commercial operation for SONGS 2 as June 1975 and for SONGS 3 as June 1976 at the time a certificate of public convenience and necessity to construct the two facilities was requested. Actual commercial operation dates were August 18, 1983 for SONGS 2 and April 1, 1984 for SONGS 3. The underestimating of power plant planning and construction lead times and failure to hold construction on schedules required burning more expensive oil and gas to generate the energy not available from SONGS 2 & 3. Completion costs of the plant were further increased by additional financing costs and direct cost escalation.

If the Commission should allow conventional ratemaking for SONGS 2 & 3, the project becomes a financial bonanza for the utilities and the problems that added to the cost of SONGS 2 & 3 will benefit the utilities' investors by adding to their cash flow and continue to be a long run burden to the ratepayers. Even with the adoption of the staff's TRB methodology, SONGS 2 & 3 will continue to be a burden to the ratepayers, but there will be more of a balancing of burden and benefit for the utilities' investors. For these reasons the City supports the adoption of TRB for SONGS 2 & 3.

E. Staff's Position

1. General

The staff in response to the Commission's directives in Ordering Paragraph 6 of D.83-09-007 presented witnesses R. Knecht, R. Czahar, and R. Benjamin of the Special Economics Projects Section of the Revenue Requirements Division with their analysis of three major and four minor ratemaking options. The staff concluded that TRB was superior to all other options in satisfying the goal of economic efficiency, equitable allocation of risk, intertemporal equity among ratepayers, and avoidance of rate shock. The staff also believes that the practical impediments to implement TRB, mentioned by witness Knecht in Phase 1 no longer remain so that it is now appropriate to adopt TRB.

2. Rate Shock and Benefits of TRB

Staff defined rate shock as any "sudden rate hike due merely to a new asset being put into operation, not to changes in the efficient cost of providing service". Under this definition, applicants' greater than $700 million rate increase under conventional ratemaking represents significant rate shock. Adoption of TRB would provide the following benefits over traditional ratemaking:

a. Avoidance of Rate Shock: Conventional ratemaking would cause rates to increase by $700 million, but under TRB, the necessary rate increase would be less than $165 million.

b. More Equitable Matching of Costs and Benefits: Conventional ratemaking requires ratepayers to pay a front-loaded stream of payments even though the benefits provided by SONGS 2 & 3 are essentially constant over the life of the plant. TRB, on the other hand, provides a relatively constant revenue stream in real terms. Under conventional ratemaking, the revenue requirement in 1984 is $1.052 billion, whereas in year 2010 it would only be $58 million. By contrast under TRB, the revenue requirement is only $513 million, while in the year 2010, it is $327 million. The staff argues that this clearly shows that there is an intertemporal equity problem with conventional ratemaking.

c. Reduction of Ratepayer Losses from Uneconomic Nuclear Plants: Under conventional ratemaking, ratepayers will have to pay, in present worth, about $1.5 billion more for the operation of SONGS 2 & 3 than if the plants had not been built and electric generation came from existing plants. The staff states that this loss would be cut in half by trended rates. The savings would occur because ratepayers would retain the use of their money longer under TRB. The present value of the savings of TRB is about $800 million ($600 million for Edison and $200 million for SDG&E).

d. Promotion of Economic Efficiency: The staff states that the economic failure of SONGS 2 & 3 resulted from at least five specific problems in the utilities' resource planning over the last decade: (1) overestimating future electric loads, (2) underestimating power plant lead times and the failing to hold construction on schedules, (3) underestimating plant costs and failing to hold costs within budget, (4) underestimating cost of capital to support construction, and (5) overestimating expected levels of performance for new base load plants and failing to achieve target levels.

Staff contends that conventional ratemaking contributed to these problems because of its cost-plus nature and front loading. While avoided cost ratemaking would solve these problems, the staff is not recommending avoided cost-based rates because it would threaten the financial health of the companies and severely penalize shareholders. Staff recommends TRB because it more closely approaches the model of economic efficiency than conventional ratemaking and although it retains the cost-plus feature of conventional ratemaking, it substantially reduces front-end loading.

3. TRB Financial Statistics

Staff also states that TRB will enable the companies to meet or exceed the average of most financial indicies for utilities with similar bond ratings and to greatly exceed all of their own recorded financial statistics. Staff analyzed the performance of Edison and SDG&E under ten key financial indicators under TRB ratemaking and conventional ratemaking. The staff analysis showed that TRB will enable Edison and SDG&E to meet or exceed the 5-year average for most of the financial indicators for utilities with similar bond ratings, and to greatly exceed all of their own respective recorded financial statistics. In fact, the staff finds that in seven of the ten financial indicators TRB performs virtually the same or reasonably close to the performance of conventional ratemaking. Regarding the remaining three indicies, while TRB does not perform as well as conventional ratemaking, by 1988 it will enable Edison to greatly exceed the averages of their own recorded financial statistics for the years 1978-1983 when it maintained a AA-rating and will give SDG&E indicators well above the average for A-rated utilities. Staff argues that if we assume rating agencies use objective and rational criteria for determining the credit worthiness of these two utilities, one can only conclude that the prospects under TRB are for them to at least maintain and more likely to exceed the criteria for AA and A ratings, respectively.

Staff argues that although the companies expressed intense concern about the purported fears of the financial community, neither Edison nor SDG&E presented any evidence upon which this Commission could form an objective opinion about whether TRB might weaken the utilities' financial health. The only attempt made by Edison to quantify the effects of TRB was in the testimony of Dr. Roll. Staff argues that Dr. Roll's argument that TRB would cause an increase in the net present value of future rates of at least $545 million was based upon erroneous assumptions and an invalid methodology. Staff further argues that its witness Danner showed that Dr. Roll's data contained so much uncertainty as to preclude their use in fixing the cost of capital numbers used in Dr. Roll's testimony. Further, the staff argues that Dr. Roll's biggest blunder resulted from his assumption that Edison will grow at the rate of eight percent per year.

4. TRB and Accounting Requirements

Staff contends that there is no impediments to the implementation of TRB from the standpoint of GAAP. Although Edison and SDG&E witnesses have attempted to raise doubts about whether TRB met GAAP, staff argues that they failed to identify a single GAAP which would prohibit the Commission from adopting TRB.

The staff's TRB proposal requires the deferral of a portion of the return that would otherwise be a component of the current revenue requirement. The return that is deferred is included in rate base and recovered over the remaining life of the plant. Second, because the objective of the staff's proposal is to have rates remain stable over the life of the plant, in real dollars, the staff also recommends that sinking fund depreciation be used instead of straight line depreciation.

The staff believes that there is no conflict between provisions in FASB 71 and that portion of APB Opinion 6 which reads: "The board is of the opinion that property, plant, and equipment should not be written up by an entity to reflect appraisal, market or current values which are above cost to the entity." Staff believes that APB Opinion 6 refers to the writing-up of an asset and not the ratemaking authority's power to create such an asset. The staff witness stated that if the staff recommendation was to simply reduce the rates that ratepayers would pay for SONGS 2 & 3 and told the Commission to issue an order authorizing the companies to write up the asset for the difference this would clearly and unequivocally violate GAAP. TRB, however, would not violate GAAP because the Commission would make a clear statement that it was deferring earnings and will permit recovery in future periods of the assets created by such deferral. Staff indicated that this was similar to the capitalizing of AFUDC used during the construction period and the recovery of such AFUDC in future periods in the form of rates. Staff also testified that figures developed using TRB can be reported and included in their published financial statements as well as filings before the SEC. Staff testified that the utilities are doing this currently in their 1983 annual reports under the MAAC balancing account and that no exceptions were taken by their independent public accountants.

5. Income Tax Issues

Staff disagrees with applicant's contention that there are possible income tax problems associated with adoption of TRB with regard to the normalization requirements of ACRS and the rateable flow through requirements for investment tax credits. Staff quoted from Economic Tax Recovery Act of 1981, Law and Explanation, published by Commerce Clearing House, Inc., page 189, Use of Normalization Method defined.—"For purposes of subparagraph (A), in order to use a normalization method of accounting with respect to any public utility property—

> "(i) the taxpayer must, in computing its tax expense for purposes of establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, use a method of depreciation with respect to such property that is the same as, and a depreciation period for such property that is no shorter than, than the method and period used to compute its depreciation expense for such purposes;—"

Staff states that it has complied with the above mandate by using a sinking fund depreciation method for both book purposes and to compute tax expense for ratemaking purposes. It has also used a 30-year life to compute book depreciation and the same life in computing tax expenses. Staff argues that witnesses Reenders and Dacek's testimony that the IRS might construe TRB as being an attempt to flow-through the benefits of accelerated depreciation more rapidly as nothing more than red herring.

Staff concludes that conventional ratemaking has failed because it has encouraged inefficiency and economic waste. TRB should now be adopted as part of a new direction in utility ratemaking which will promote economic efficiency. Staff seriously doubts that SONGS 2 & 3 would have been built had not investors expected cost-plus ratemaking. Staff believes that although avoided cost pricing is the economic ideal for promoting efficiency and fairly allocating costs and risks, it does not recommend adoption of avoided costs because it would unfairly penalize investors. However, staff believes that it is appropriate for the Commission to make a transition toward avoided cost rates by systematically adopting TRB for SONGS 2 & 3 initially and then for other utility assets. It recommends that the Commission order utilities to undertake a similar quantitative analysis of TRB presented by the staff in this case to determine whether TRB should be applied broadly to all other utility assets or all bulk electricity supply assets. Staff states that it has provided the Commission with all details required for implementing TRB for SONGS 2 & 3 except for the choice of an asset appreciation index. Staff in its brief recommends the adoption of the gross national product deflator series as an appropriate index.

F. Position of Other Parties

Harold Boxer filed a brief and argued against SDG&E's financial policy of paying interest and dividends from the proceeds of new debt and common stock issues necessitated by the building of SONGS a decade before there was a need for the investment. To correct the problems of negative returns which SDG&E has sustained for at least the past 5 years, Boxer recommends that:

SDG&E be prohibited from making capital investments to increase generating capacity. All necessary costs to extend distribution system be billed to property owners who benefit from such hook-up.

2. Restrict SDG&E's authorized return on common equity to the average for the entire industry as reported for the past 12 months in Moody's electrical utility average.

3. SDG&E be required to utilize the full authorized return on rate base to retire long-term debt after interest and mandatory debt requirements have been met.

Boxer opposes the adoption of TRB as being unnecessary and disruptive at this time. He believes that his proposal provides a solution to SDG&E's current financial problems.

Consumer Coalition of California (Consumers) representing Southern California Edison customers argued that despite the cheapest oil prices in a decade, and conservation practices of the customers the cost per kWh have increased because of the large gray albatross called SONGS 2 & 3. Consumers believes that the wiwndfall gains enjoyed by Edison from the recent heat wave should be used to compensate for the cost of owning and operating SONGS 2 & 3. Consumers recommends that no rate action be taken on SONGS until an accounting of the effects of the recent heat waves have been made.

Toward Utility Rate Normalization (TURN) argued that since 1980 rates in California have risen twice as fast as the rest of the country as a whole and that Edison is rated as one of the preferred utilities by Wall Street. Therefore, there is no reason to feel sorry for Edison. TURN supports the staff's TRB proposal and opposes the adoption of a cap on TCF as unnecessary since it views the TCF as already being too weak.

Mr. Duncan argued in support of the staff's position on the TCF cap and complimented the staff for its TRB proposal.

G. Discussion

We requested the parties to examine the various ratemaking approaches not because we wished to change for change's sake, but because we suspected that SONGS 2 and 3 were sufficiently different from a typical addition to plant to require unconventional treatment. In particular, we were concerned that the following features of the SONGS project might render the plants unsuitable for conventional treatment:

1. The enormous capital cost of the plants.
2. At current estimates of costs, the addition of SONGS 2 & 3 will represent about 40% of the utilities' rate bases.
3. The tenfold increase in the project's cost from the time of certification to the time of completion.
4. The effect on rates of such a large addition to plant.
5. The disappointing performance record and low capacity factors of certain other nuclear plants.

An additional concern was not specifically related to the SONGS project but had particularly disturbing implications for an addition to rate base as large as SONGS 2 and 3. This concern grew out of our realization that the inflation that had grown to unusually high levels in the late 1970s and that was persisting in the early 1980s had altered the essential capital recovery scheme assumed in traditional ratemaking. While inflation is currently at comparatively low levels, it may increase again during the lifetime of the plants and therefore is a factor to be considered.

If we assume no inflation under the conventional approach, the utility's cost recovery, the ratepayers' payments, and the project's benefits are fairly stable over time. Intertemporal equity is well served, as ratepayers' costs are closely matched to the benefits they receive.

However, inflation affects the balance between the utility's capital recovery and the benefits received by ratepayers. During inflationary times, ratepayers in the first part of the plant's life pay rates that are much greater than the benefits they receive, because inflation usually requires higher returns on the undepreciated portion of the plant's cost. On the other hand, ratepayers in the latter part of the plant's life pay rates that are much less than the benefits they receive, because inflation increases the value of the plant's output. With the effect of inflation, traditional ratemaking becomes an increasingly front-loaded capital recovery scheme.

The interaction of these concerns with conventional ratemaking treatment of SONGS 2 and 3 had two troubling implications. First, we were concerned that ratepayers during the early years of operation would bear a disproportionate share of the costs of the plants. Ideally, today's ratepayers should pay the same price in constant dollars for a unit of electricity produced by a plant as ratepayers 29 years from now, at the expected end of the same plant's useful life. Staff's analysis, which assumed 6 percent general inflation, showed the potential extent of this problem. According to staff, conventional ratemaking would require Edison's ratepayers to pay $460 million per year net of fuel savings in 1984, but ratepayers in the 30th year would receive a net benefit of some $1.1 billion, in nominal dollars.

The second disturbing implication arises from the fact that we cannot be absolutely sure that the plants will operate for their entire projected useful lives. This is a risk which we must not ignore. Under conventional ratemaking, the utility recovers most of the return on its investment quickly, in the early years of operation, because it earns its rate of return on the undepreciated capital costs, which are high in the early years. If the plant fails in the fifteenth year of operation, for example, the ratepayers would have paid most of the plant's total revenue requirement, although the plant would have operated for only half of its useful life. The utility, on the other hand, will have recovered a large majority of its total expected revenues from the operation of the plant, so even if the plant is removed from ratebase, the utility's loss will be disproportionately small. When the actual effects (as opposed to the normalized, ratemaking treatment) of ITC and ACRS are considered, it is clear that the utilities recover not only most of their revenue requirements, but most of their capital investment, in the form of tax breaks, in the early years of a plant's operation. Our concern here is twofold: that the risk of a plant's early failure falls disproportionately on ratepayers, and that utility management will have a lessened financial incentive to assure that the plant operates for its full useful life.

Regrettably, this risk for early failure is not an insignificant consideration. In California alone we have seen the unexpected, early closing of the Humboldt nuclear plant of Pacific Gas and Electric Company and a lengthy outage of the SONGS 1 plant, which forced us to consider whether to remove that plant from rate base. Thus, the risk of early failure even though it may be low, cannot be ignored.

These considerations make the alternative ratemaking proposals presented in this proceeding very attractive to us. In particular, the trended rate base proposal developed by staff provides an interesting method of balancing the interests of ratepayers, the utilities, and investors.

The utilities raise several arguments in opposition to TRB.

Edison asserts that application of TRB is unlawful because it fails to meet the standards of the classic Hope and Bluefield cases. In essence, Edison argues that deviating from conventional original cost ratemaking will result in revenues so low as to be legally unreasonable, at least in the early years of the plants' lives.

We do not believe that Hope and Bluefield bind us to a single method of ratemaking. As the Court stated in Hope, regulators are "not bound to the use of any single formula or combination of formulae in determining rates" (320 U.S. at 602). Further, "[t]he rate-making process . . . i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests" (320 U.S. at 603). Staff has demonstrated that TRB may provide a fairer balance of these interests and may be accommodated to the essential investor interest of the financial integrity of the company. Therefore, we are not legally prevented from adopting TRB.

Edison makes its legal objections specific to SONGS 2 and 3 by stating that Hope and Bluefield require the Commission "to establish rates which provide revenue for both investment-related costs and noninvestment-related expenses of the public utility property at the time such property is being used to provide service to the public." (Edison's Opening Brief, p. 12.) We should make it clear that our search is not for a method of denying the utilities their investment-related costs; we are here determining how those investment-related costs should be recovered. As we have said, we find nothing in Hope or Bluefield that binds us to straight-line depreciation ratemaking. As Hope said, "it is the result reached not the method employed which is controlling" (320 U.S. 602). We believe that TRB could be applied to SONGS 2 and 3 in a manner that would be consistent with the requirements of both Hope and Bluefield.

The utilities also raise the objection that TRB would violate accounting rules and would create enormous potential tax problems for them.

We believe that TRB can be accommodated to accepted accounting practices. Staff, the proponent of TRB, presented the testimony of an accountant who asserted that TRB would comply with GAAP as applied to regulated utilities. The utilities' opposition to this testimony was tentative and to the effect that problems might arise. We will accept the testimony of staff on these accounting matters.

Similarly, the utilities raise the issue of tax problems in a tentative fashion. We do not believe that we should allow a fear of what the IRS might do or how a regulation might be interpreted deter us from taking a new direction. If we were deterred by such fears and speculations, we would never be able to take innovative action. Also, since accounting for regulation and accounting for taxes are different in many respects, we are not convinced that the adjustments required by TRB will necessarily come under the scrutiny of the IRS.

The utilities also counter the argument that TRB enhances intergenerational equity by pointing out that past generations of ratepayers have paid for many of today's resources under conventional ratemaking. Thus, today's ratepayers, the ones who will pay disproportionately for SONGS 2 and 3, are at the same time benefitting disproportionately from the resources paid for by earlier ratepayers.

While this argument is true as far as it goes, it neglects certain differences between the SONGS plants and the other plants in the resource base. First, the old plants were nowhere nearly as expensive as SONGS 2 and 3, so the burdens borne by earlier generations are not necessarily comparable. Second, many of the older plants were built during a period when the marginal costs of additional generation were declining, so that ratepayers gained immediately through lower marginal operating costs when a new plant came on line, thus mitigating the rate effect of adding the new resource to rate base. Third, many of these earlier plants were oil- or gas-fired, so the fuel costs which in recent years have constituted most of the cost of the electricity produced by the plant were being paid for by the same ratepayers who received the power; the potential for intergenerational subsidy, at least in recent times, was smaller than for more capital-intensive plants like SONGS 2 and 3. We suspect that the intergenerational subsidies associated with conventional treatment of the SONGS plants far exceed the subsidies enjoyed by today's ratepayers.

As we have discussed, the effect of inflation on conventional ratemaking creates considerable problems of intertemporal inequity. TRB might help minimize the distortions that inflation adds to the traditional capital recovery scheme and thus might produce, on the whole, a result that is fairer to the various generations of ratepayers than application of the conventional approach to the SONGS project.

Some might argue that adopting TRB would seem to require one crucial premise, namely that inflation will continue over the 30-year useful life of SONGS 2 and 3. Although recent history suggests that this might well be a correct assumption, we are reluctant to try to predict the course of the economy for such a long period. Upon reflection, however, it becomes apparent that this assumption is unnecessary. If inflation is less than the level recently experienced, capital recovery under TRB merely comes closer to the recovery profile of the conventional approach. Although TRB provides an ideal balance to the distortions created by high inflation, it also allows fair capital recovery in noninflationary times.

Thus, TRB has many attractive characteristics that would help alleviate some of our concerns about the effect on ratepayers of applying conventional ratemaking to SONGS 2 and 3. However, we also see several difficulties with applying TRB.

First, there is the question whether rate shock will result from conventional treatment. For example, a rate increase of 12 percent for Edison's customers would result from conventional treatment of both plants. We have already incorporated into rates, through the MAAC, an increase of about 4 percent. Thus, conventional recovery of all of the project's costs would require a further increase of 8 percent. (Other Edison applications may also affect rates, of course.) This is not the level of increase that would usually be thought of as rate shock. Moreover, in this decision we are providing for another increase in MAAC rates for purposes of rate stabilization. Accordingly any increase granted after Phase 2 will be reduced, further lessening the "shock" to customers.

Second, staff's assertion that conventional ratemaking inefficiently favors capital-intensive plants is not entirely convincing. Even if we accept staff's assertion, it is not clear that the utilities' current planning would be affected much by a different ratemaking treatment, since the utilities' planning has already turned from capital-intensive plants to alternative generation, conservation, load management, and purchases of other utilities' surplus energy and capacity. The historical example of hydroelectric plants also shows that some capital-intensive plants can be a very cheap source of electricity.

Third, no convincing response was given to the utilities' argument that we should consider the cost of O&M as well as the investment-related costs in developing a scheme of rates that is fair to both current and future ratepayers. It is reasonable to expect O&M expense to rise over time, because of inflation and the aging of the plants. This increasing O&M expense tends to level the front-loaded capital recovery profile of conventional ratemaking. The addition of O&M expenses to TRB ratemaking might also distort one of the intents of TRB - to equalize the burden on present and future ratepayers.

Fourth, staff responded in part to the utilities' assertions that TRB would deny them a reasonable return on equity by pointing out that the utilities would have ample cash flow to pay dividends (Staff's Reply Brief, p.16). The source of part of this cash flow is the normalization for ratemaking purposes of accelerated depreciation and investment tax credits. Recently, however, several plans for Federal tax reform have proposed the repeal of ITC and the closer tying of tax depreciation to economic depreciation. The proposals received serious public attention only after the submission of this case, and none of the parties have had an opportunity to comment on the plans' implications. Which plan, if any, is adopted remains uncertain. We raise this concern because it creates a new uncertainty in an area that is central to the TRB proposal. This uncertainty, in turn, makes us somewhat more reluctant to adopt a ratemaking change whose cash-flow implications may not be clear for a year or more.

After weighing the advantages and disadvantages of both conventional ratemaking and TRB, we have determined that SONGS 2 and 3 should receive the conventional treatment.

Staff also urged us to apply TRB to all plant additions that have received certificates but have not yet begun operations. We decline to adopt staff's recommendation. As we have discussed, our choice of ratemaking treatments for SONGS 2 and 3 is primarily grounded in the particular circumstances of the plants' construction and the effects on current and future ratepayers. We will not adopt a blanket rule requiring TRB, but staff may raise the issue in other proceedings.

VI. Target Capacity Factor

A. General

In D.83-09-007 the Commission ordered the parties to this proceeding to analyze whether a cap beyond the 50-50 sharing should be placed on the utility exposure resulting from the target capacity factor (TCF) performance standard. In addition, other implementation issues with respect to the TCF relating to how the TCF should interact with other regulatory mechanisms, the use of economic modifiers in the TCF calculation, the use of a separate TCF calculation for each company were heard in the Phase 1B proceedings.

B. Edison's Position

1. TCF Cap

Edison states that the fundamental goal of the TCF should be to encourage the providing of electric service to ratepayers at the lowest practically achievable total cost. If the TCF is structured as a performance incentive mechanism, there must be a proper allocation of risk to achieve the goal of encouraging good performance while limiting total cost to ratepayers. If risk allocation is carried too far it can result in increased capital costs and consequently higher rates to ratepayers. This requires a cap to be placed on the TCF.

Edison states that the TCF will increase the total risk perceived by investors and that without a cap the TCF will increase Edison's cost of capital. Edison's witnesses Executive Vice President Christie, F. Jeffries of Duff and Phelps, Inc., and E. Meyer of Kidder, Peabody & Co., Inc. testified on the risk perceived by investors on an uncapped TCF. Witness Christie testified that an annual cap not greater than $25 million on before-tax earnings on all nuclear units in which Edison has an ownership share would be appropriate. When taken in conjunction with the AER cap, Edison's full exposure would be approximately $75 million.

Edison disagrees with the staff that the impact of the TCF without a cap is minimal and that the deadband is generous. While the staff analysis focuses strictly on two important parameters: return on equity and interest coverage, they are only two out of many considered by investors. Edison further considers the staff's analysis showing a 426 basis point pre-tax impact on return on common equity should SONGS 2 & 3 operate at zero capacity for a year as a substantial risk. This amounts to a reduction in the return on common equity from 16 percent to 14 percent. Such risk is sure to increase the cost of capital and result in higher costs to ratepayers.

Edison states that its financial witnesses Jeffries and Meyer both testified that the investment risks as perceived by investors will increase because of the adoption of TCF. Jeffries stated that up to now investors had expected fuel and purchased power costs would be recovered through the ECAC mechanism. Now under TCF, investors will realize that there is a change in the rules and that there are increased investment risks. These changes in favor of the ratepayers impose a penalty on existing shareholders and ultimately result in a higher cost of common equity. Witness Meyer also stated that uncertainty as to future earnings because of TCF and deferral of cash earnings is perceived by investors to be an increase in the risk to be borne by investors. Witness Christie further testified that the goal of TCF should be to provide an incentive to Edison to minimize the total energy cost to its customers and that there is no overall benefit to customers if that goal is achieved at the expense of an increase in the cost of capital. Christie believes that a cap of $25 million on before-tax earnings would strike a reasonable balance between the Commission's perceived need for an incentive on the performance of the company's nuclear units and the need to maintain a financially viable utility.

2. Interaction of TCF with Other Regulatory Mechanisms

At issue is whether the 50-50 sharing of replacement energy costs or savings due to SONGS 2 performance outside the TCF deadband is to apply to 100 percent of the replacement energy costs or savings due to Unit 2 performance or to 90 percent of energy costs or saving normally subject to ECAC and not subject to the AER. Edison argues that the language of D.83-09-007 is not clear with respect to the interaction of the TCF and the AER. Literal application of the language in Resolution E-1990 produces an incentive procedure which is applicable to 100 percent of Unit 2 production and resultant replacement energy costs or savings, plus an additional 10 percent of Unit 2 production and resultant replacement energy costs or savings reflected in the AER. This is depicted in the following chart:

TCF + AER

100 Percent of Unit 2 Production Subject to the TCF

10 Percent of Production Subject to the AER

10% also subject to AER

\+

10% subject to AER

=

110% of Unit 2 Production Subject to Incentives

Same 10%

Note: The condition depicted in the chart results in 100 percent of Unit 2 production being subject to the TCF and 10 percent also being subject to the AER. This results in 110 percent of the Unit 2 production being subject to incentive provisions.

Application of the TCF to all energy expenses rather than to only those expenses not subject to the AER results in 110 percent of SONGS 2 production being subject to incentives. Edison states that this is not an equitable result and probably was not the Commission's intent. Edison believes that the Commission instituted the TCF procedure to provide Edison with an incentive to efficiently operate SONGS 2. All any incentive procedure can do is attempt to influence 100 percent of a power plant's production and associated replacement energy costs and savings. Edison states that the most logical interpretation of the Commission's objective is to have the combination of the AER and the TCF affect 100 percent of the SONGS 2 production and replacement energy costs or savings. Thus, the AER should influence 10 percent of SONGS 2 production and replacement energy costs or savings, and the TCF should influence the remaining 90 percent.

In support of its position, Edison quotes from page 55 of D.83-09-007:

> "As further explained below, we consider a SONGS 2 performance standard to be complementary to the AER. At the present time, a relatively small percentage of fuel costs are placed in the AER for both Edison and SDG&E. A SONGS 2 performance standard would apply to the ECAC portion of costs and would therefore contribute further to performance efficiency and equitable risk allocation..." (Emphasis Added.)

Edison argues that the above language clearly provides that the AER incentive and the TCF incentive are to be complimentary to each other. If the TCF were applied to the 10 percent of energy expenses recovered through the AER, the result is not complimentary but overlapping or duplicative. Edison further states that application of the TCF reward or penalty to the 90 percent of energy costs recovered through the ECAC Balancing Account is more consistent with the Commission's intent to have shareholders and ratepayers share 50-50 the replacement energy costs or savings resulting from operation of SONGS 2 outside the deadband.

Edison further states that the Commission established the procedure to determine the acceptable range for the Forecasted Capacity Factor to be used in AER calculations when it stated on page 61 of D.83-09-007:

> "Each year an appropriate target level for the plants' capacity factor will be set, as it is now, in the ECAC/AER forecast proceeding. In no case shall the SONGS 2 forecasted capacity factor for ECAC/AER purposes fall outside the deadband. Assuming that the forecasted capacity factor for ECAC/AER purposes falls somewhere within the middle of the deadband (e.g., 72%) the current AER incentive (for Edison, ten cents on the replacement fuel dollar) will apply to actual annual capacity factor performance that is above or below the target but within the deadband (e.g. 55-72, 72-80). When capacity factor performance diverges from the target to the extent that it falls outside of the deadband, an additonal TCF reward or penalty of 50% of associated replacement fuel savings or costs shall apply."

Edison states that the logical interpretation of this language is that the Commission meant the AER to operate with respect to performance inside the Deadband; for performance outside the Deadband, since the AER continue to operate with respect to 10 percent of the replacement energy costs, the TCP should operate on remaining 90 percent of replacement energy costs not subject to the AER. Any TCP reward or penalty will thus be 50 percent of those replacement energy costs. This will result in a 55-45 sharing of total replacement energy costs or savings and a 50-50 sharing of only those replacement energy costs that would otherwise be recovered by the ECABF (Energy Cost Adjustment Billing Factor).

Edison also contends that replacement energy costs resulting from operation outside the deadband and subject to TCP are not subject to traditional ECAC reasonableness review. The additonal TCP reward or penalty referred to by the Commission in the above quoted portion of D.83-09-007 is, according to Edison, in addition to the application of the AER incentive applied to actual "capacity factor performance that is above or below the target but within the deadband". In further support of its position Edison cited language from page 62 of D.83-09-07 in which the Commission said "Recovery of the portion of replacement fuel costs for SONGS 2 not subject to AER and the adopted TCP will still be subject to annual prudency reviews through the ECAC procedure".

Edison asserts that the Commission's intent with respect to the operation of the various replacement fuel cost adjustment mechanism is best described by the following chart:

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Edison also contends that replacement energy costs resulting from operation outside the deadband and subject to TCF are not subject to traditional ECAC reasonableness review. The additonal TCF reward or penalty referred to by the Commission in the above quoted portion of D.83-09-007 is, according to Edison, in addition to the application of the AER incentive applied to actual "capacity factor performance that is above or below the target but within the deadband". In further support of its position Edison cited language from page 62 of D.83-09-07 in which the Commission said "Recovery of the portion of replacement fuel costs for SONGS 2 not subject to AER and the adopted TCF will still be subject to annual prudency reviews through the ECAC procedure".

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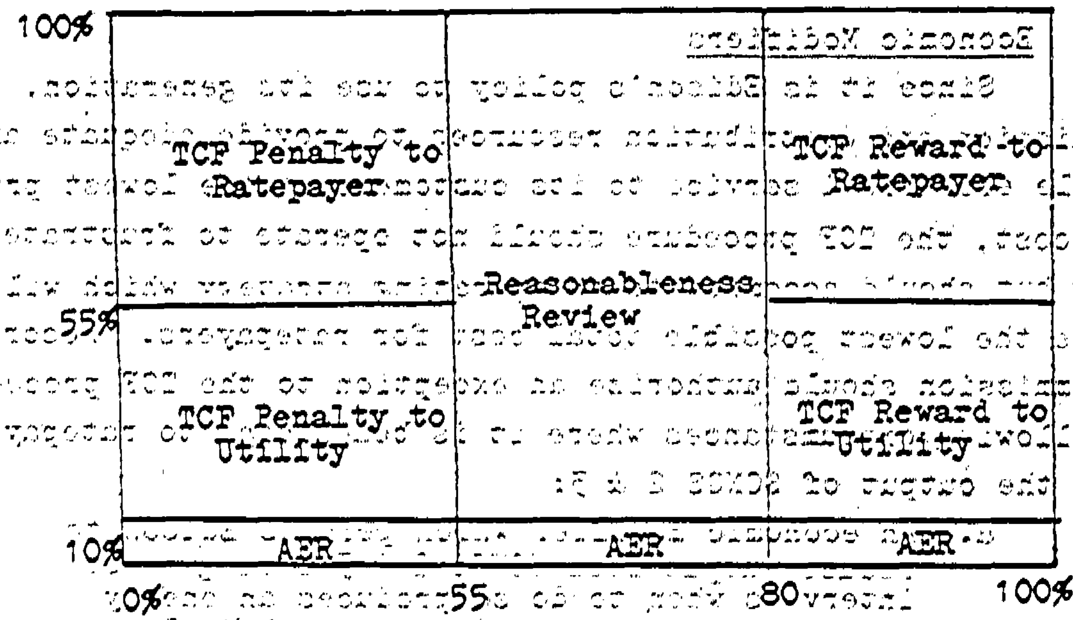

Percent Annual Capacity Factor

Within the deadband the AER operates in conjunction with the ECAC reasonableness review, whereas, for performance outside the deadband, the AER operates in conjunction with the TCF only, and not the ECAC reasonableness review. The TCF applies only to those costs not subject to the AER. The application of the TCF reward or penalty to the 90 percent of replacement energy costs depicted in the above chart is consistent with the coal plant incentive procedures adopted for Edison's Mohave and Four Corners Coal Plants.

3. Economic Modifiers

Since it is Edison's policy to use its generation, transmission and distribution resources to provide adequate and reliable electrical service to its customers at the lowest practical total cost, the TCF procedure should not operate to frustrate this policy but should accommodate an operating strategy which will achieve the lowest possible total cost for ratepayers. Accordingly, the Commission should authorize an exception to the TCF procedure in the following circumstances where it is beneficial to ratepayers to reduce the output of SONGS 2 & 3:

a. An economic modifier which permits Edison to reduce output from SONGS 2 & 3 during those intervals when to do so produces an energy supply to meet system demand which is less costly to ratepayers.

b. An economic modifier which removes the possibility of a TCF penalty when Edison changes a refueling outage schedule for either SONGS 2 & 3 when in the best interest of ratepayer.

c. The Commission should recognize as a general principle in the TCF tariff, that the TCF should not be construed in such a way to penalize Edison when the output of SONGS 2 & 3 is reduced for the economic benefit of Edison's ratepayers, with Edison required to bear the burden of proof of demonstrating in the ECAC reasonableness review that an exception to the TCF procedure is warranted on the basis of an economic modifier.

4. Separate TCP Calculations For Each Utility

Since Edison owns 75.05 percent of SONGS 2 & 3 and SDG&E 20 percent and each utility controls its respective ownership share with respect to dispatching and/or resale of its share of the output of SONGS 2 & 3, the present TCP tariff could affect the TCP reward or penalty for the other utility despite the fact that the other utility may be taking 100 percent of its entitlement. If SONGS 2 & 3 were capable of operating at 100 percent capacity and Edison for some reason found it necessary to reject its 75 percent share, the plant would be forced to operate at 25 percent capacity and SDG&E would be placed in a penalty situation. This would be true even if SDG&E was taking 100 percent of its entitlement. This would be grossly unfair. Therefore, Edison proposed that when the output of either SONGS 2 or 3 is reduced and the reduced output is not divided in proportion to the ownership share, the respective utilities are rewarded or penalized under the TCP only in proportion to the reduction in their share of the output.

5. Technical Issues

The first technical issue raised by Edison is the use of the gross or net rating in the TCP calculation. Edison states that gross rating of 1127 MW should be used for TCP purposes, because of simplicity of measurement and calculation. The net output would be after deduction of the plant loads at SONGS 2 & 3 which are about 60 MW for Unit 2 and 50 MW for Unit 3. These loads may vary with different conditions of plant operation by 10-20 MW. The gross output figure does not vary with plant load and therefore provides a fixed value which would be desirable.

The second technical issue raised was the appropriate record period to be used in computing target capacity factor reward or penalty. While the current TCF provides for an annual computation of TCF reward or penalty both Edison and staff now agree that a complete fuel cycle is the appropriate period. The fuel cycles of a nuclear power plant are the natural frequency at which the plant operates and are thus the logical intervals over which to calculate any performance standard such as TCF. Since the initial startup period requires numerous tests and does not represent normal operation of the units under TCF, Edison recommends that the TCF record period for the first fuel cycle of each unit begin with that unit's COD. Subsequent cycles would begin with the startup from refueling for that particular core, and all cycles would end at the time the refueling outage is completed.

C. SDG&E's Position

1. TCF Cap

SDG&E states that in order to evaluate the impact of adopting a cap on the long run interests of the ratepayers, it is essential to look at two elements: (1) the expected cost increase to the ratepayers due to their assumption of certain additional risks if a cap is adopted for the TCF and (2) the additional capital costs which must be borne by the ratepayer if there is no cap adopted for the TCF. SDG&E states that the staff analysis shows that the expected value of the additional risk that would be borne by the ratepayers if a reasonable cap is adopted by the Commission would be fairly low because of the low probability of extreme occurrences. On the other hand, the increase in cost of capital based upon the investment community's perception of risk, is highly impacted by the extreme cases due to the perception of risk in the financial community. This is because investors are fearful that nuclear generating units will be out of service for periods much longer than for conventional fossil fuel units. Thus the financial community believes that a low or zero capacity factor has sufficient potential to be alarmed by the potential results of such a case. SDG&E believes that the increasing cost of capital due to the uncapped TCF is likely to be substantially greater than the expected value of risk transferred to the ratepayers through Commission's adoption of a reasonable cap.

Reasons for the perceived risk by the investment community as stated by F. Jeffries of Duff & Phelps are:

a. TCF is a new item under which the investors are being asked to share a portion of the risk from changing fuel costs which they had not previously borne.

b. The potential for penalty is substantially greater than the opportunity for reward.

c. Investors are fearful of long out of service periods due to NRC requirements.

d. In the absence of a cap, investors are concerned that the exposure to risk may be considerably greater in the future due to increasing replacement power costs.

While a cap cannot eliminate all of these concerns, it can limit the maximum exposure of investors to a level which will hopefully not result in added capital costs to be borne by the customers.

SDG&E further argues that adoption of a TCF without a cap is inconsistent with the cautious approach adopted in prior Commission decisions regarding fuel related incentive clauses. The non-cautious approach without a cap can be seen in the risk associated with the maximum penalty under the TCF mechanism of 449 basis points compared to the limited exposure of 120 basis points adopted for the AER in D.83-08-048. The maximum risk for SDG&E under TCF is 449 basis points while that for Edison is 426 basis points. This risk relationship is completely contrary to the appropriate risk relationship found reasonable by the Commission in D.83-08-048 in which a lower AER cap was found reasonable for SDG&E compared to Pacific Gas and Electric Company and Edison because of SDG&E's greater earnings variability.

SDG&E developed its recommended cap by first looking at the level of penalty which would be reached with a 10 percent probability based on observed capacity factors at other large pressurized water reactor plants. It calculated the 50 percent pre-tax exposure to shareholders from additional fuel costs at that 10 percent level of exposure to be $9.1 million pre-tax. The maximum additional AER exposure due directly to SONGS 2 was $4.3 million pre-tax. There was an additional $2.2 million of risk added to the AER due to the increase in the AER cap with the addition of SONGS 2 to rate base and earnings. Subtracting these amounts from the $9.1 million pre-tax leaves an appropriate cap for the TCF penalty of $2.6 million pre-tax with a similar amount for SONGS 3.

SDG&E tested the appropriateness of the $2.6 million cap by comparing the ratio of AER cap to fuel cost revenue associated with the cap and the TCF cap to the total revenue requirement for SONGS 2. The fuel cost revenue requirement was $746 million compared to a

$140 million revenue requirement for SONGS 2 or 1/5th the revenue requirement for fuel. Thus based on this 1:5 relationship, the $6.7 million cap for AER would equate to a $1.7 million pre-tax cap for the TCF. Since the $1.7 million cap is substantially less than the $2.6 million cap previously computed, SDG&E concluded that the $2.6 million pre-tax cap was reasonable.

2. TCF and AER

SDG&E states that it understands and agrees that the reward/penalty computed under the TCF is in addition to any reward or penalty computed under the AER mechanism. However, SDG&E does not believe that the TCF and AER are intended to be duplicative with respect to the AER costs. SDG&E states that the initial mention in D.83-09-007 of the SONGS 2 performance standard computation indicated that it would apply to the ECAC portion of costs. All subsequent reference in the decision to costs or replacement fuel costs should logically be referenced back to this initial statement.

SDG&E further argues that common sense also dictates that the costs intended to be shared are those which are available for adjustment at the time of the TCF calculation. The AER costs are calculated on a month by month basis and are allocated directly to the utility's expense during each monthly period. On the other hand, the TCF calculation is currently scheduled to be done annually or prospectively on a fuel cycle basis. The TCF penalty, if any, will be folded into the ECAC balancing account to offset the costs that are allocated into the balancing account; namely, the 92 percent of fuel costs which are allocated in the ECAC balancing account. SDG&E concludes logic dictates that the TCF penalty should only be applied to those costs which are subject to balancing account treatment in the ECAC.

SDG&E also states that the language in D.83-09-007 with reference to the proper sharing of costs between the ratepayer and the investor is ambiguous, leading to three possible interpretations of the Commission's intent.

1. The Commission intended that the total risk of fuel cost savings and excesses be shared equally between the investor and the ratepayer after consideration of both the AER and the TCF:

	Investor	Ratepayer
AER/ECAC	8%	92%
plus TCF transfer	42%	(42%)
Total	50%	50%

2. The Commission intended that the fuel savings or excesses normally borne by the ratepayers (the ECAC costs) would be split between the ratepayers and the investors. This would be in addition to the normal cost excess responsibility borne under the AER by the investors:

	Investor	Ratepayer
AER/ECAC	8%	92%
plus TCF transfer	46%	(46%)
Total	54%	46%

3. The Commission intended that the investor receive a reward or a penalty based upon 50% of the excess fuel costs borne by both the ratepayer and the investor. This again would be added to the 8% of the fuel costs risk already borne by the investor and would result in windfall profits or losses for the AER portion of the costs:

	Investor	Ratepayer
AER/ECAC	8%	92%
plus TCF transfer	50%	(50%)
Total	58%	42%

While all three of the interpretation meet the Commission's directive in Paragraph 5 of Resolution E-1990, SDG&E believes that interpretation 2 reflects the Commission's intent. However, in order to eliminate the confusion currently contained in D.83-09-007 and Resolution E-1990, SDG&E requests that the Commission clarify its intended calculation by stating the proper sharing between the investor and ratepayer based upon the added AER and TCF as either 50-50, 54-46, or 58-42 total investor/ratepayer ratio.

3. TCF Modifiers

SDG&E supports the modifiers upon which there is substantial agreement between the staff and applicants. First, the TCF calculation should be modified so that each utility's capacity factor is calculated based exclusively upon the performance of that utility's share of the SONGS units. Second, the incentive period included in the TCF factor should be modified from the current annual calculation to a calculation for a full fuel cycle. Finally, the TCF calculation should be modified to include at least the two specific modifiers identified in this phase of the hearings.

1. back down of the units when required by economic dispatch, and
2. modification of power levels to avoid refueling outages during summer peak periods. SDG&E also agreed to the limitation that these economic modifiers would only apply to reduce a potential penalty, but would not be used to enhance any reward situation.

D. City's Position

1. Economic Modifiers

City states that it has no basic objection to the economy energy economic modifier concept except for the fact that it is unnecessary and leaves the door ajar for further attempted manipulations. City is concerned that even if the Commission adopts Mr. Cavagnaro's condition that economic modifiers only be recognized to offset penalties, the issue of converting this one-way street to a two-way street will be a constant source of litigation in the ECAC proceedings dealing with the TCF computation.

City, however, has very basic objections to either the "coastdown or speedup proposal". If these modifiers are allowed in the tariffs, the door is wide open for game playing by the utilities. If a plant is operating at a reduced capacity, for whatever reason, and its normal fuel cycle ends during the summer months, it will be designated as operating in a coastdown or speedup mode by the utility. As soon as the plant can be operated at full capacity, the conditions requiring the coastdown or speedup will have miraculously changed. City believes that the workload on the staff to efficiently monitor these situations will be quite large. City believes that the Commission has adopted an extremely generous deadband for the TCF and if the Commission is sincere in its stated purpose of using the TCF as an allocation device designed to fairly allocate risks, costs, and benefits between shareholders and ratepayers, it should reject all attempts to slant the game in the utilities' favor.

2. TCF Cap

City agrees with staff witness, Pulsifier, that no TCF cap be adopted for reasons cited by Mr. Pulsifer in Exhibit 51 and also because the Commission has already built into the TCF certain features that are designed to limit investors exposure. City states that it recognizes, as did the Commission in D.84-04-052 that perceptions of either the need for or the level of a cap may be related to perceptions of risk stemming from the operation of the deadband or the handling of extrinsic factors. City, therefore, recommends that if the Commission opens up the door by allowing economic modifiers then there should be no cap. If, on the other hand, the Commission keeps the door closed and believes that the TCF exposes the utility to increased levels of risk, then a reasonable cap might be considered.

3. TCF and AER

City states that it disagrees with Edison's interpretation that the TCF reward or penalty applies only to those costs not subject to the AER. City argues that language in D.83-09-007 makes it absolutely clear that the TCF penalty or reward has nothing to do with the AER and that there is an additional reward or penalty when performance falls outside of the deadband.

4. TCF and Reasonableness Review

City agrees with the staff that exemption of SONGS from a reasonableness review, if operation is outside the deadband, is completely illogical. City agrees with witness Cavagnaro that the Commission has not and should not adopt a standard which substitutes for a reasonableness review and which would reward Edison for an imprudent action.

5. Separate Company TCF Calculations

City believes that on its face Edison's proposal to modify the TCF procedure to allow separate company calculation of capacity factor appears to be fair and reasonable. However, City is concerned that in the implementation of the proposal there may be the opportunity and possibility of the utilities' manipulating the computation of the TCF. Before the Commission adopts this concept, it should assure itself that the concept cannot be manipulated to the detriment of the utilities' ratepayers.

E. Staff's Position

1. TCF Cap

Staff alleges that Edison's $25 million TCF cap proposal when applied to SONGS 2 & 3, based upon current replacement fuel costs, is equivalent to the current 50 percent shareholder obligation at about the 45 percent capacity factor level. For one unit, it is equivalent to the shareholders' obligation at the 35 percent capacity factor. Staff states that Edison does not understand or could not bring itself to represent the ratepayers' perspective on TCF.

Similarly, staff characterizes SDG&E's proposed cap of $2.6 million for each unit would mean that the TCF will not apply below the 48.7 percent capacity factor. SDG&E determined that the cap should be triggered by events having a 10 percent probability of occurring, which would be at a 33 percent capacity factor. The replacement fuel cost was then determined to be $9.1 million. The $9.1 million was reduced by $4.3 million because the shareholders are already exposed to that level of risk under the AER. A further reduction of $2.2 million was made to eliminate the risk added to the AER due to the increase in the AER cap with the addition of SONGS 2 to rate base, leaving a $2.6 million balance. Staff argues that there is no ground for the original $9.1 million because SDG&E's witness had to assume that the AER and TCF operated similarly. Staff had to assume that the AER and TCP operated similarly. Staff states that the AER is strictly an incentive for utility efficiency, whereas, the TCP was designed mainly as a risk allocation device.

Staff states that it was the only party to analyze whether a cap beyond the 50-50 sharing should be placed on utility exposure resulting from the adopted TCP performance standard. Staff witness T. Pulsifer analyzed the exposure of Edison and SDG&E's stock and bondholders under the TCP. He examined the effect of the TCP on the cost of equity capital by considering the impact of various capacity factors on the return on equity. He found that for Edison, a 20 percent capacity would produce a 150 basis point pre-tax decrease in the return on equity for one unit and a 243 basis point decrease for both units at 20 percent capacity factor.

For SDG&E the results are similar. The pre-tax impact on return for equity for a 20 percent capacity factor for either plant would decrease earnings by 154 basis points and for both plants operating at 20 percent capacity a 253 basis point decrease. The witness further testified that while the magnitude of the replacement fuel costs obligation is large for capacity factors of 20 to 0 percent, the probability of encountering such penalties is very low.

The staff witness further maintains that the real effect on earnings is determined not only by the TCP but by the AER effects as well. Gains in the AER may offset losses on the TCP, so that despite catastrophic low capacity factors, the shareholders may have a limited liability. Staff further calculated the effect of the various capacity factor penalties upon pre-tax interest coverages. Staff found for Edison that a zero capacity factor for SONGS 2 would lower the 1984 forecasted interest coverage by 0.15x to 3.74x and for SDG&E it would lower 1983 recorded interest coverage by 0.18x to 3.52x. These figures are above the industry averages for AA and A rated utilities.

Staff concludes that the TCP does not produce unacceptable increases in the cost of capital and there is no reason to adopt a TCP cap. Staff argues that the companies view the TCP solely as an incentive procedure. However, TCP is not only an incentive procedure but primarily a risk allocation procedure. Moreover, should the Commission adopt the various modifications to the TCP supported by staff, such as economic modifiers and the extended TCP period, the likelihood of the companies suffering any penalty will be substantially reduced.

Staff anticipated that SONGS 3 will be subject to the TCP procedure when it becomes operational and accordingly the scope of its recommendation addressed both SONGS 2 & 3.

2. Economic Modifiers

Staff witness Cavagnaro testified in response to Edison's request to adopt certain economic modifiers in computing the capacity factor under TCP. Witness Cavagnaro concluded that if the Commission considered the TCP as a risk sharing mechanism, then there is justification for not including exceptions or allowing mitigating factors to enter into the TCP formula. However, if the Commission views the TCP as a performance incentive, then specific actions to enhance economic efficiency should be recognized in the TCP. If economic modifiers are to be allowed the witness recommended that they be used to offset penalties and be supported by detailed records and individually justified in each case. He further recommends that the utilities be required to submit detailed reports regarding opportunities to make economy energy purchases whether or not the plants operate within the deadband or actually reduce output to take advantage of cheap energy.

The staff witness felt that based on the history of SONGS the second modifier, where power levels are reduced to extend plant operation through summer peak periods are infrequent and do not indicate the need for a modification of the TCP standard. However he did not offer objections to the Commission's recognizing coastdowns in plant output to extend the fuel cycle as a mitigating factor if it was used only to offset penalties and if they are supported by detailed records and justified in each case. He also emphasized that any actions taken to extend the fuel cycle require comprehensive economic analysis not only of the utility's own capacity requirements, but also of those of other utilities in the state. He also recommends that whenever the utilities consider extending the fuel cycle and makes the appropriate economic analysis, the utilities should send copies of the analysis to the staff within 15 days after a decision has been made, regardless of whether the utility decides to reduce output. In addition, the utility should be required to furnish the staff with a full account of all actions taken as a result of its decision to extend the fuel cycle. While the staff does not oppose adoption of the two economic modifiers, it does oppose the granting of a blanket economic modifier.

Staff counsel reluctantly supports the use of economic modifiers. Since the utilities already have the obligation of providing the least cost energy to ratepayers, the utilities in theory would have to make adjustments in SONGS 2 & 3 generation to maximize economy energy purchases and to provide sufficient energy for summer peak demand. Staff counsel argues that the TCP is primarily a risk-sharing device rather than an incentive for performance. The wide deadband already insulates the utilities from substantial risk which is borne by ratepayers. Staff counsel is concerned because the utilities have demonstrated a repugnance to risk-sharing and may manipulate the economic modifiers to avoid penalties. Staff counsel recommends that the Commission allow the limited economic modifiers only if a cap is not adopted.

3. TCP and Reasonableness Review

Staff characterizes the applicants' recommendation that the TCP serve to replace any reasonableness review of ECAC fuel expenses for any capacity factor outside of the deadband as preposterous. Staff admits that it may be difficult to do a reasonableness review of SONGS 2 & 3 and even more difficult to show imprudency, however, it is outrageous to suggest that the reasonableness review be abandoned as long as ratepayers are required to pay 50 percent or more of the replacement fuel expenses for capacity factors below the TCP deadband.

4. TCP and AER Relationship

Staff argues that Edison and SDG&E are simply asking the Commission to change its mind about the interaction between the AER and TCP established in D.83-09-007 and confirmed by Resolution E-1990. Staff claims that the utilities' claim that the Commission's intent was ambiguous is simply not true. Staff argues that the Commission explicitly stated in D.83-09-007 that the AER and TCP are separate procedures, and intentionally designed the TCP as an additional reward or penalty.

The staff further argues that the Commission was also aware that there is an overlap or double counting of AER benefits and burdens if the TCP applies to 100 percent of the fuel costs for capacity factors above or below the deadband. There is nothing wrong with having the AER and TCP apply together since the Commission intended it to be that way when it referred to the TCP as an additional reward or penalty. In addition, the amount of the overlap is not very significant because the Commission adopted a wide deadband where there is 90 percent probability of operating within this range. Furthermore while there will be overlapping, outside the deadband the amounts are small. In the worst case, with a zero capacity factor, the difference would only be $8 million for Edison and $2 million for SDG&E. The probability of a zero capacity factor occurring is about 1 percent. The staff also argues that the Commission should recognize that the AER overlap also allows utility shareholders to earn duplicative AER rewards when the capacity factor exceeds 80 percent. If the overlapping AER is excluded from the TCF then the staff suggests that the deadband should be correspondingly reduced to preserve the sharing or risks between ratepayers and shareholders found reasonable in D.83-09-007 be preserved.

5. TCF Period

During the course of the proceeding staff witness Cavagnaro suggested to the utilities that the TCF period should be calculated over a full fuel cycle rather than the one-year period implied in D.83-09-007 or the two-year period suggested by the companies. The advantage of a fuel cycle is that the TCF varies significantly depending upon whether the plant is refueling in the year considered. Edison anticipates almost three months downtime for the first refueling. Thus the maximum capacity factor achievable would be 75 percent where as in the following year, when no refueling is anticipated, a 100 percent capacity factor could be achieved. Edison accepted the staff's recommendation and presented witness M. Medford to submit criteria for the commencement and termination of the fuel cycle.

F. Discussion

1. TCF Cap

Staff, after detailed study came to the conclusion that an earnings cap on the TCF should not be adopted because it would weaken the intent of the TCF; it could produce misleading signals regarding overall investor earnings; while the TCF could generate losses that exceed the maximum losses under the AER caps, it is not known whether the probabilities of such large losses are significant; TCP has protective features that limit the magnitude of potential losses; a TCP cap would introduce unnecessary flexibility to the TCP procedure; the Commission has already concluded in Phase 1 of these proceedings that investors will be no worse off due to TCP since the required returns and cost of capital will be small and will likely be totally offset by the reduction in risk associated with commercial operation of the plant; and finally, even at the extreme end of the range of TCP of 0 percent capacity factor, the effects on pre-tax interest coverage would still leave each utility at or above the industry average for interest coverage.

In opposition to the staff position the utilities claim that the investors will perceive increasing risks borne by shareholders due to the TCP procedure which they were not required to bear previously. Edison takes exception to the staff's conclusion that when you consider the magnitude of loss and the probability of its occurrence, the expected loss for Edison for a 20 percent capacity factor for SONGS 2 would be $3.3 million. Similarly, SDG&E's expected loss would only be $435,000. Staff states that there is less than a 3 percent probability of the plant operating below 20 percent capacity factor, but in their calculation of the $3.1 million expected loss, the staff has changed this to be a 3 percent probability of the plant operating at a 20 percent capacity factor. Edison points out that the staff's exhibit shows an $88 million pre-tax loss for Edison at a 20 percent capacity factor. For SDG&E the pre-tax impact at a 20 percent capacity factor would be $26 million according to Exhibit 51.

Applicants also disagree with the staff's conclusion that shareholders have limited liability under the TCF procedure because gains in the AER may offset penalties calculated under TCF. The AER operates such that 10 percent of the estimated energy costs for a 12-month period are recovered through a rate which is fixed and not subject to balancing account treatment. In an extreme case, if SONGS 2 & 3 did not produce any energy during the forecast period, Edison would incur replacement energy costs at the company's marginal cost of energy which is generally above the cost of nuclear generation. The fact that the AER procedure may provide a reward or penalty to shareholders due to other differences between forecasted costs and recorded costs is irrelevant to the determination of the impact upon shareholders due to the TCF procedure since AER rewards or penalties would occur irrespective of the operation or non-operation of SONGS 2 & 3.

The impacts of the AER and TCF procedures are additive. The fact that TCF losses may be offset by AER gains does not limit shareholder liability. The incremental impact of the TCF procedure is its gain or loss. Edison further states that the staff's conclusion ignores the fact than any AER losses incurred will be added to the TCF losses, and that when the TCF procedure produces a penalty AER losses are more probable than AER gains.

SDG&E alleges that its TCF cap proposal recognizes that the TCF as well as the AER are both risk sharing and incentive procedures. It also recognizes that the TCF and the AER are interrelated, since they both deal with fuel expenses. SDG&E believes that its cap proposal considers the total risk borne by ratepayers as well as investors through all the risk sharing mechanisms adopted by the Commission and develops the reasonable total risk to be borne by the utility for the SONGS units. SDG&E states that its TCF cap proposal established a reasonable maximum risk which would allow fulfillment of the incentive objective of the TCF, as well as a risk sharing portion. The additional risk placed upon the utility would not be so ominous as to cause substantial increases in the cost of capital due to this risk.

We have carefully considered the testimony of the various witnesses and the arguments of the various parties to this proceeding. We disagree with the staff that the TCF was primarily adopted as a risk sharing mechanism. We also disagree with applicants' contention which appears to be slanted toward classifying the TCF as primarily an incentive procedure. We adopted TCF because it has attributes of both a risk sharing and an incentive procedure. The staff has shown that the impact of zero capacity factor for SONGS 2 & 3 on pre-tax common equity return for Edison would be $138 million decrease with a 382 basis point reduction in the return on equity for Edison and for SDG&E a $42 million reduction with a 410 basis point reduction in the return on equity. Pre-tax interest coverage at zero capacity factor also shows a decrease of 0.30x for Edison and 0.35x for SDG&E. These figures in and of themselves do not indicate that a zero capacity factor operation would devastate the utilities' financial condition or their ability to attract capital. We are aware that investors are concerned about the impact of the TCF with or without a cap and that the pre-tax impacts of TCF at 20 percent capacity factor of $88 million and at zero capacity factor of $138 million are sizeable impacts, even if the probabilities that such an event are occur are low. The same would hold true for SDG&E if not even more so because of the higher impact on return on common equity.

On the other hand, we are of the opinion that the $25 million pre-tax penalty cap for all nuclear power plants in operation recommended by Edison and SDG&E's $2.6 million penalty cap for each unit are insufficient and substantially alter the risk-sharing aspects of TCF.

On balance, we conclude that a cap on the TCF is not appropriate. The TCF was initially intended as a risk-sharing mechanism, but it also has some of the characteristics of a performance mechanism. To limit the utilities' potential costs to $25 million or $2.6 million, as suggested by Edison and SDG&E, would necessarily result in a substantial increase in the risk borne by ratepayers. We cannot justify further insulating the utilities from these risks at the expense of ratepayers, who, of course, have no influence on the operations of the plants. Shareholders are already protected from extreme loss by the fact that we require ratepayers and shareholders to share equally in the benefits and costs resulting from the operation of the SONGS plants outside the TCF deadband. Further limitation of the utilities' exposure to risk is inequitable, unnecessary, and unwise.

2. TCP and AER

Applicants have argued and submitted testimony on the interaction of TCP to AER and whether it was the intent of the Commission in D.83-09-007 to have the 50-50 sharing of replacement energy costs or savings due to SONGS 2 performance outside the TCP deadband apply to 100 percent of the replacement energy costs or savings or to 90 percent of energy costs or savings normally subject to ECAC and not subject to AER. Applicants cannot believe that the Commission intended to have 110 percent of the SONGS 2 energy expenses be subject to incentives, 100 percent under the TCP and 10 percent under the AER. Applicants believe that this is an inequitable result and contrary to the Commission's intent. Applicants state that the language in D.83-09-007 is confusing and believe that there are three possible interpretations on how the Commission intended the AER and TCP should interact and that all three would meet the Commission's directive in Paragraph 5 of Resolution E-1990. To end this confusion, applicants request that the Commission indicate the proper sharing between the ratepayer and investor based upon the added AER and TCP.

Staff, on the other hand, argued that there is no confusion as to the intent of the Commission about the interaction between the AER and TCP established in D.83-09-007 and confirmed by Resolution E-1990. Rather than confusion, staff alleges that applicants are requesting the Commission to change its mind.

We have reviewed applicant's testimony and arguments as well as the position taken by the staff. We agree that the language contained in D.83-09-007 could be interpreted in the various ways described by applicants. We agree with applicants that it was not our intent to have duplicative penalties under the AER and TCP. Therefore, we agree that when SONGS 2 & 3 production falls below the deadband the 50 percent penalty would apply to the ECAC portion of the replacement energy cost. The AER would complement the TCF by taking care of the remaining 10 percent of the replacement energy cost for Edison and 8 percent of the replacement energy cost for SDG&E.

3. Reasonableness Review

We have reviewed the respective arguments as to whether the TCF serves to replace the reasonableness review of ECAC fuel expenses. Although D.83-09-007 states "Recovery of the portion of replacement fuel costs for SONGS 2 not subject to AER and the adopted TCF will still be subject to annual prudency reviews through the ECAC procedure" the decision does not say that recovery of the portion of replacement fuel costs for SONGS 2 subject to the TCF would not be subject to annual prudency reviews. We concur with the staff and City that it would not be reasonable for this Commission to adopt a standard that would waive the reasonableness review and which would reward applicants for imprudent action when operations are outside the deadband.

4. TCF Modifiers

As we have indicated earlier, we consider the TCF to be both a performance incentive procedure as well as a risk allocation procedure. We believe it is reasonable to adopt the two economic modifiers which (1) permit applicants to reduce output from SONGS 2 & 3 during those intervals when to do so produces an energy supply to meet system demand which is less costly to ratepayers, (2) remove the possibility of a TCF penalty when Edison changes a refueling outage schedule for either SONGS 2 & 3 when in the best interest of ratepayers. These modifiers would be subject to two conditions: (a) it only be recognized to offset penalties and (b) that any adjustment be supported by detailed records and individually justified in each case. The utilities will be required to provide such detailed information as part of the report on the operation of each SONGS unit whether or not each of the units operates within the deadband. In connection with modifier number 2, we will require Edison to provide to the staff the results of the analysis on an ongoing basis within 15 days after a decision has been made. In addition as part of the operating report, it will be appropriate for the utility to provide complete information on both the economic analysis used for the decision and what actually transpired after the action had been undertaken.

Edison also recommended that the capacity factor for TCP purposes be computed separately for each utility in proportion to each utility's ownership share and in proportion of the production taken. By having separate calculations each utility would stand on its own and would not be rewarded or penalized because one partner failed to take its share of the output. We believe this request is reasonable and will adopt this modification.

5. Technical Issues

The first technical issue raised by Edison was the use of a gross or net rating in the TCP calculation. Edison supports the use of the gross rating of 1127 MW for TCP purposes because of simplicity as well as the fact that it does not vary with plant load. We will adopt the use of the gross rating for TCP purposes since the proposal is reasonable and none of the parties raised any objections.

The second technical issue raised was the appropriate record period to be used in computing the TCP reward or penalty. Both staff and applicants have agreed that a complete fuel cycle is the appropriate record period since it represents a natural cycle. We will adopt the recommendation. The first fuel cycle for each unit will begin with the COD for each unit and would end at the time the refueling outage is completed. All subsequent cycles would begin with the start up from refueling for that core.

VII. Revenue Requirement and Related Issues

A. Revenue Requirements

Edison states that Phase 2 will address the reasonableness of the costs incurred on SONGS 2 & 3. However, Phase 2 is not expected to be completed until mid-1985. It is therefore necessary to address the issue of the appropriate amount of investment-related revenue requirement which should be reflected in cash rates prior to the completion of Phase 2. In addition the issue of how, when and in what amount the deferred debit account accruals should be amortized and several technical tariff issues remain to be resolved.

Edison originally requested that in its Phase 1B decision the Commission:

a. Authorize a rate increase of $368.4 million to bring cash rate levels for SONGS 2 & 3 up to 100 percent of the revenue requirement;

b. Authorize reducing the MAAC Balancing Account by a credit of $2,842,472 to clear the SONGS 2 deferred debit account; and

c. Adopt Edison's proposed MAAC tariff to correct an error in the presently effective MAAC tariff with respect to jurisdictional calculations.

Of the total $874.8 million, SONGS 2 & 3 revenue requirement $506.4 million have been reflected in rates leaving $368.4 million revenue requirement not reflected in rates and accruing in the MAAC balancing account. Edison states that as of June 1, 1984, $163 million of undercollections had been accrued in the MAAC balancing account. This amount is equivalent to $715 million of Edison's plant investment in SONGS 2 & 3. Therefore, the undercollection of $163 million should be sufficient to provide the Commission with adequate flexibility to deal with Phase 2 issues. Furthermore, Edison states that all investment-related revenues from

SONGS 2 & 3 are subject to adjustment in a final Commission order in Phase 2. Without rate action, the MAAC balancing account will continue to grow at approximately $30.7 million per month and increase to more than $600 million by October 1, 1985. Edison believes that it is detrimental to Edison's ratepayers to permit the undercollected balance to accrue to levels greater than the minimum amount the Commission feels is necessary to retain flexibility. To avoid the problem of dealing with large amounts of undercollections in the future, Edison requests that the Commission authorize a rate increase of $368.4 million, or 8 percent, to bring cash rate levels up to 100 percent of the revenue requirement for SONGS 2 & 3.

At the Phase 1B oral argument held on September 13, 1984, Edison modified its Phase 1B revenue requirement increase and now seeks a Phase 1B rate increase of $300 million or an increase of about 6½ percent. The reason given for the reduction in the rate increase sought was attributed to a combination of a reduction in revenue requirement due to accrued depreciation and an increase in the level of sales which would reduce the annual revenue shortfall to about $300 million. We further note that Edison by letter dated September 2, 1984 has advised the Commission that it will not be filing revisions to its MAAC for changes in 1985 investment-related costs for SONGS 2 & 3 because its revised reduced request took into consideration the 1985 revenue requirements.

Edison further stated at the oral argument that a Phase 1B decision granting a $300 million rate increase as of November 1, 1984 will leave a $290 million undercollected balance in the MAAC balancing account, and that amount would increase by approximately $25 million a month if further cash rate relief is not authorized in Phase 1B. Edison further states that the $290 million undercollection in the MAAC balancing account as of November 1, 1984 represents the capital recovery, including earnings, for nearly 20 percent of Edison's share of the plant investment over a 2-year period.

SDG&E similarly requests that the Commission grant a rate increase of the remaining $103.5 million in investment-related revenue requirements for SONGS 2 & 3. This would satisfy the Annual Ownership Rate (AOR) offset requirements and would limit further accumulations in the MAAC balancing account to interest payments on the balances as of the date of a decision in Phase 1B. SDG&E further requests that the audited amount in the MAAC balancing account as of December 31, 1983 of $75.3 million be amortized by granting a rate increase of $118.8 million. SDG&E states that by the time a decision in Phase 1B is issued, the MAAC balancing account would have accrued over $80 million in undercollections and that such amount should be adequate to protect the ratepayer's interest in Phase 2. SDG&E further states that even if the Phase 2 decision results in adjustments in excess of the $80 million, ratepayers are protected by the balancing account mechanism.

B. Tariff Issue

Edison states that the presently effective MAAC tariff contains an error with respect to certain jurisdictional calculations and therefore does not correctly reflect the intended operation of the MAAC. Paragraphs L.4 and L.8 presently direct that the authorized annual revenue requirement stated in subparagraphs L.4.a. and L.8.a. respectively, be jurisdictionalized and increased to provide for franchise fees and uncollectible expenses. The error in the tariff is that the amounts reflected in the subparagraphs have already been adjusted.

Discussion

We have considered Edison's revised request for cash rate relief for SONGS 2 & 3 of \$300 million or approximately 6½ percent for this Phase 1B decision and find that such request is reeasonable. This will result in an estimated undercollection of \$360 million in the MAAC balancing account at the end of 1985. Such amount is equivalent to capital recovery, including earnings for nearly 20 percent of Edison's share of the SONGS 2 & 3 investment over a 2-year period. This should enable the Commission to retain sufficient flexibility to cope with any Phase 2 disallowances. Furthermore since the investment-related costs for SONGS 2 & 3 are subject to balancing account procedures ratepayers will not suffer even if the revenue requirement on disallowances should exceed the balances in the MAAC balancing account.

While SDG&E did not modify its request similar to Edison at the Phase 1B oral argument from the \$103.5 million previously requested, we believe that it would be reasonable to restrict the cash rate relief granted to SDG&E to the same magnitude granted to Edison in Phase 1B. We will therefore authorize SDG&E cash rate relief of \$84 million in this decision. Although SDG&E requested that it be granted additional rate increase of \$15.3 million to amortize the MAAC balancing account undercollections as of December 31, 1983 we will deny SDG&E this additional rate relief at this time to be consistent with Edison and to retain in the MAAC balancing account an equivalent amount of undercollections pending the outcome of the Phase 2 decision on reasonableness. By retaining the undercollected balances in the MAAC balancing account we are not attempting to prejudge the outcome of the Phase 2 reasonableness review, but merely retaining flexibility to cope with any disallowances without causing excessive rate fluctuations.

We also adopt Edison's request to modify the MAAC tariff in order to correct the error in the tariff to conform with the corrected language used in Exhibit 8, Appendix D.

VIII. Findings and Conclusions

Findings of Fact

1. In D.83-09-007 in A.82-02-40 of Edison and A.82-03-63 of SDG&E the Commission established a Phase 1B to consider the need for a cap on the TCF adopted in that decision as well as to consider alternative ratemaking methodologies for SONGS 2 & 3.

2. On October 4, 1983 Edison made a supplemental filing in A.82-02-40 to reflect 1984 investment and noninvestment-related cost figures for SONGS 2. On October 5, 1983 SDG&E filed A.83-10-12 requesting similar updating of SONGS 2 costs for its 20 percent share of SONGS 2.

3. On October 21, 1983 Edison filed A.83-10-36 requesting that SONGS 3 be given similar MAAC treatment from the COD of SONGS 3 through December 31, 1984. On November 4, 1983 SDG&E filed A.83-11-19 for MAAC treatment for its 20 percent interest in SONGS 3.

4. These matters were consolidated for hearings in Phase 1B.

5. In D.84-01-034 dated Janaury 5, 1984, an order modifying D.83-09-007 and denying rehearing, the Commission requested the parties in the proceeding to file briefs on whether the deferred debit accounting authorized in D.84-01-034 constituted retroactive ratemaking.

6. On June 14, 1982, the ALJ issued a ruling setting a COD criteria for SONGS 2 which was ratified by the Commission by Minute Order on July 21, 1982 and subsequently confirmed by D.82-09-111.

7. On August 8, 1983, Edison released SONGS 2 to the system dispatcher for firm operations and triggered the plant in service date according to FERC accounting rules.

8. On August 18, 1983, SONGS 2 completed its 200-hour run at 100 percent power thereby achieving the Commission COD criteria.

9. On September 6, 1983, a Commission staff member visited SONGS 2 and confirmed that SONGS 2 had met the Commission's COD criteria on August 18, 1983.

10. On September 7, 1983, the Commission issued D.83-09-007 authorizing Edison and SDG&E to establish the MAAC balancing account procedure to reflect certain ownership costs for their respective interests in SONGS 2.

11. In Finding 79 of D.83-09-007, the Commission stated "should the COD be met prior to the issuance of this decision, it is reasonable for applicants to continue accruing Allowance for Funds Used During Construction (AFUDC) on SONGS 2 investment, capitalize operating and maintenance expenses, and credit any energy generated by SONGS 2 at avoided cost to the work order until MAAC rates become effective".

12. Both Edison and SDG&E filed applications for rehearing requesting, among other things, a modification of Finding 79 to avoid conflicts with FERC accounting regulations and the CPUC in-service date by authorizing deferred debit accounting rather than continued accruals in the SONGS work order.

13. For purposes of California ratemaking, SONGS 2 began commercial operations on August 18, 1983.

14. The estimated cost of SONGS 2 & 3 is now ten times greater than when the plants were first proposed.

15. At the current estimated cost, SONGS 2 & 3 would represent about 40% of the utilities' rate bases.

16. The capital recovery profile of conventional ratemaking becomes increasingly front-loaded with increasing levels of inflation.

17. All commercial nuclear power plants in California have suffered unexpected and sustained outages.

18. At the 6% inflation assumed in the analyses submitted in this proceeding, conventional ratemaking requires current ratepayers to pay too much and later ratepayers to pay too little, relative to the benefits they receive.

19. While conventional ratemaking initially results in higher revenue requirements, in future years it results in lower revenue requirements, because of the steady reduction in investment-related costs included in rate base.

20. It is probable that O&M expenses for SONGS 2 & 3 will increase over time.

21. Increasing O&M costs have the effect of leveling the front-loaded nature of conventional treatment of the addition of SONGS 2 & 3 to rate base.

22. A rate increase of $300 million for Edison (equivalent to a 6½ percent increase in rates), and a corresponding increase of $84 million for SDG&E to cover investment related costs for SONGS 2 & 3 are reasonable.

23. It is reasonable to increase Edison's MAAC rates by $300 million. It is reasonable to increase SDG&E's MAAC rates by $84.0 million, in proportion to the ownership shares of the two utilities.

24. It is reasonable to make the rate changes ordered in this decision effective on January 1, 1985 in coordination with other pending changes in rates.

25. It is reasonable for Edison to modify the MAAC tariff to correct the tariff to conform with the corrected language used in Exhibit 8, Appendix D. (See Appendix A.)

26. The TCF mechanism provides for an equal sharing of risks and benefits between ratepayers and shareholders.

27. It is not reasonable to increase ratepayers' risks and reduce shareholders' risks by adopting a cap on the TCF.

28. We find that the language contained in D.83-09-007 and Resolution E-1990 relating to the interaction of TCF with AER needs to be clarified. It was not the intention of the Commission to have duplicative penalties under the AER and the TCF. When SONGS 2 & 3 production falls below the deadband, the 50 percent penalty should apply only to the ECAC portion of the replacement energy cost. The AER would complement the TCF by taking care of the remaining 10 percent of the replacement energy cost for Edison and the remaining 8 percent of the replacement energy cost for SDG&E.

29. Replacement energy costs resulting from operation outside the deadband and subject to TCF are subject to traditional ECAC reasonableness review. It would be unreasonable to reward applicants for imprudent actions when operations are outside the deadband and require reasonableness review only when it is within the deadband.

30. The TCF is both a risk allocation mechanism, and a performance incentive. We therefore find it reasonable to adopt the two economic modifiers which permit applicants to reduce output from SONGS 2 & 3 during those intervals when to do so produces a energy supply to meet system demand which is less costly to ratepayers, and which remove the possibility of a TCF penalty when Edison reschedules a refueling outage for either SONGS 2 & 3 when in the best interest of

ratepayers. These modifiers are subject to the conditions set forth in Appendix B and be used only to offset penalties.

31. It is reasonable to compute the capacity factor for TCF purposes separately for each utility in proportion to each utility's ownership share and in proportion to the production taken. By having separate calculations each utility would stand on its own and would not be rewarded or penalized because one partner failed to take its share of the output.

32. It is reasonable to use the gross rating of 1127 MW for each unit of SONGS 2 & 3 for TCF purposes because of simplicity and the fact that the gross rating does not vary with plant load.

33. It is reasonable to use a complete fuel cycle as the appropriate record period to be used in computing the TCF reward or penalty since it represents a natural cycle. The first fuel cycle for each unit will begin with the COD for each unit and would end at the time the refueling outage is completed. All subsequent cycles would begin with the start up from refueling for that core.

34. It is reasonable to adopt the TCF procedure for SONGS 3 as adopted for SONGS 2.

Conclusions of Law

1. The Commission's action in authorizing deferred debit accounting for SONGS 2 costs for the period from August 18, 1983, the commercial operation date, to October 8, 1983, the date that rates authorized in D.83-09-007 became effective, constituted retroactive ratemaking in violation of PU Code § 728.

2. For SONGS 2, for purposes of California regulation, Edison and SDG&E may record AFUDC, O&M expenses, property and payroll taxes, and a credit at avoided cost prices for energy generated until August 18, 1983, the COD.

3. Edison and SDG&E may recover the fuel costs, calculated in cents per kWh, of SONGS 2 for actual generation from August 18, 1983, in their respective ECAC and AER accounts. Generation during this period should not be credited at the utilities' avoided cost rates.

4. Accruals in the MAAC accounts created in D.83-09-007 may begin as of September 7, 1983.

5. Recovery of noninvestment-related costs may begin on October 8, the date that AMAR became effective.

6. TRB can be accommodated to the requirements of Hope and Bluefield.

7. TRB can be accommodated to generally accepted accounting practices and to the requirements of the Internal Revenue Code.

8. Current circumstances do not justify the application of TRB to SONGS 2 & 3.

9. The TCF incentive procedures adopted in D.83-09-007 for SONGS 2 should be similarly applied to SONGS 3.

10. The TCF procedure adopted in D.83-09-007 should not be modified to include a TCF penalty cap.

11. The economic modifiers as shown in Appendix B should be adopted for the purposes of calculating any TCF penalty.

12. The capacity factor for TCF purposes should be calculated separately for each utility in proportion to each utility's ownership share and in proportion to the production taken.

13. For TCF purposes the gross rating of 1127 MW for each SONGS unit and the use of a complete fuel cycle as the record period should be adopted.

14. Replacement energy cost resulting from operation outside the deadband and subject to TCF are subject to the ECAC reasonableness review.

15. When SONGS 2 & 3 production falls below the TCF deadband, the 50 percent TCF penalty will apply only to the ECAC portion of the replacement energy costs. The AER will complement the TCF with respect to the remaining replacement fuel costs.

16. The rates and charges authorized in this decision are justified and reasonable.

17. The effective date of this order should be the date on which it is signed to prevent excessive undercollected balances from being accumulated in the MAAC balancing accounts.

INTERIM ORDER

IT IS ORDERED that:

1. Southern California Edison Company (Edison) is authorized and directed to file with this Commission revised MAAC Ownership Rate tariffs increasing such rates by $300 million annually to cover the investment-related costs of SONGS 2 & 3. Such tariffs shall be effective on the date filed, but no earlier than January 1, 1985. The tariff schedules shall comply with General Order (GO) 96-A and shall apply to service rendered on or after the effective date of the tariff schedules.

2. San Diego Gas & Electric Company (SDG&E) is authorized and directed to file with this Commission revised MAAC Ownership Rate tariffs increasing such rates by $84 million annually to cover the investment-related costs of SONGS 2 & 3. Such tariffs shall be effective on the date filed, but no earlier than January 1, 1985. The tariff schedules shall comply with GO 96-A and shall apply to service rendered on or after the effective date of the tariff schedules.

3. Recovery of the investment-related costs of SONGS 2 & 3, as determined to be reasonable in Phase II of this proceeding, shall follow the conventional straight-line depreciation, original cost approach.

4. The Target Capacity Factor (TCF) standard adopted for SONGS 2 shall also apply to SONGS 3.

5. The TCF modifiers set forth in Appendix B are adopted for SONGS 2 & 3.

6. The capacity factor for TCF purposes will be computed separately for each utility in proportion to each utility's ownership share and in proportion to the production taken.

7. The appropriate record period to be used in computing the TCF reward or penalty is a complete fuel cycle. The first fuel cycle

for each unit will begin with the COD for each unit and would end at the time the refueling outage is completed. All subsequent fuel cycles would begin with the start up from the refueling for that core.

8. For TCF purposes the gross rating of 1127 MW for each unit of SONGS 2 & 3 will be used.

9. When SONGS 2 & 3 production falls outside of the deadband, the 50 percent reward or penalty should apply only to the ECAC portion of the replacement energy cost or savings.

10. When SONGS 2 & 3 production falls below the TCF deadband, the replacement energy costs are subject to ECAC reasonableness review.

11. Edison is authorized to file revised MAAC tariff Sections L.4 and L.8 to correct errors in the tariffs to conform to the corrected language in Exhibit 8, pages II-8 and II-9 (See Appendix A).

12. Edison and SDG&E shall make the accounting adjustments described in this decision to reflect our conclusion that the creation of the deferred debit accounts in D.83-09-007 and D.84-01-034 constituted unlawful retroactive ratemaking.

This order is effective today.

Dated December 28, 1984, at San Francisco, California.

DONALD VIAL
President
VICTOR CALVO
PRISCILLA C. GREW
WILLIAM T. BAGLEY
FREDERICK R. DUDA
Commissioners

I dissent in part on the cap issue and on the $ amount going into rate base.

/s/ VICTOR CALVO
Commissioner

I dissent in part on the $ amount going into rate base.

/s/ PRISCILLA C. GREW
Commissioner

I dissent in part on the retroactive ratemaking issue.

/s/ WILLIAM T. BAGLEY
Commissioner

I CERTIFY THAT THIS DECISION WAS APPROVED BY THE ABOVE COMMISSIONERS TODAY.

Joseph E. Bodovitz

Joseph E. Bodovitz, Executive Director

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Southern California Edison Company

Major Additions Adjustment Clause

L.4 Calculation of the Average Ownership Rate

Individual rates to reflect certain costs of owning each specified Major Addition shall be calculated as authorized by the Commission. The Average Ownership for each Specified Major Addition shall be determined from the following calculations:

a. The Forecast Period depreciation including decommissioning reserve expense;

b. Plus: The Forecast Period ad valorem taxes;

c. Plus: The Forecast Period taxes based on income, including the following tax adjustments:

1. The tax deductions resulting from items "a" and "b" above;

2. Investment tax credits;

3. The tax effect of the excess of liberalized depreciation over booked depreciation;

4. Interest charge deductions;

5. Other appropriate tax adjustments.

d. Plus: The Forecast Period return which shall be the Forecast rate base multiplied by the Company's system rate of return most recently authorized by the Commission.

e. The sum of "a" through "d" shall be allocated to the sales subject to the MAAC estimated to be sold during the Forecast.

Period in direct proportion to the ratio of generation for such sales to total system sales.

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Southern California Edison Company

L.4 Calculation--Contd.

f. The amount in "e" above, increased to provide for Franchise Fees and Uncollectible Accounts, shall be divided by the sales subject to the MAAC estimated to be sold during the Forecast Period. The result shall be the Average Ownership Rate, expressed in cents per kilowatthour, as set forth in Paragraph 3g.

At such times as the Commission authorizes a change in the rate of return or adopts any other adjustments which affect the costs applicable for inclusion in the Average Ownership Rate, the Average Ownership Rate shall be appropriately revised.

L.8 Calculation of the Average Noninvestment-Related Expense Rate.

Individual rates to reflect certain noninvestment-related costs associated with each Specified Major Addition shall be calculated as authorized by the Commission. The Average Noninvestment-Related Expense Rate for each Specified Major Addition shall be determined from the following calculations:

a. The Forecast Period operation and maintenance expenses (excluding all costs recovered through the Company's Energy Cost Adjustment Clause or through the currently effective base rates) appropriate for inclusion in the MAAC;

b. Plus: The Forecast Period pensions and benefits expense associated with the labor portion of "a" above;

c. Plus: The Forecast Period payroll tax expense associated with the labor portion of "a" above;

d. Plus: The Forecast property, liability, and replacement generation insurance expenses;

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Southern California Edison Company

L.8 Calculation--Contd.

e. The sum of "a" through "d" shall be allocated to the sales subject to the MAAC estimated to be sold during the Forecast Period in direct proportion to the ratio of generation for such sales to total system sales; and

f. The amount in "e" above, increased to provide for Franchise Fees and Uncollectible Accounts, shall be divided by the sales subject to the MAAC estimated to be sold during the Forecast Period. The result shall be the Average Noninvestment-Related Expense Rate, expressed in cents per kilowatthour, as set forth in Paragraph 3g.

(END OF APPENDIX A)

APPENDIX B

TCF Economic Modifiers

Exception to the TCF procedure is authorized in the following circumstances where it is beneficial to ratepayers to reduce the output of SONGS 2 & 3:

a. An economic modifier which permits the utilities to reduce output from SONGS 2 & 3 during those intervals when to do so produces an energy supply to meet system demands which is less costly to ratepayers. This will accommodate additional economic power purchases.

b. An economic modifier which removes the possibility of a TCF penalty when the utilities changes a refueling outage scheduled for SONGS 2 & 3 when in the best interest of ratepayers.

These modifiers would apply only to reduce a potential penalty and must be supported by detailed records and individually justified in each case. For economic modifier b), the utilities are required to send the staff copies of any analysis within 15 days after a decision has been made to consider extending the fuel cycle, regardless of whether the utility decides to reduce output. The utilities are further required to furnish the staff with a full account of all actions taken as a result of its decision to extend the fuel cycle.

(END OF APPENDIX B)

DONALD VIAL, President, Concurring:

I write this concurring opinion solely because there appears to be come misunderstanding and/or confusion about the SONGS Major Additions Adjustment Account (MAAC) as it relates to our Phase II prudency decision and level of any under/over-collection in the MAAC.

In earlier decisions, we have wisely confined the MAAC to investment-related expenditures. Pending our prudency decision -- in order to give ourselves sufficient time to thoroughly review the amounts invested in SONGS Units II and III -- we reasoned that any under- or overcollection in the MAAC could be adjusted when we made that decision. From the date of commercial operation, the utility would be made whole for any investment-related undercollection in the MAAC, including interest, and ratepayers would be made whole for any investment-related overcollection, including interest. Clearly, the MAAC was created to enable us to start putting investment-related costs into basic electricity rates without prejudicing our pending decision concerning the amount to be actually rate based.

From a ratepayer's viewpoint, it may be argued that an undercollection should be maintained in the MAAC sufficient to cover some reasonable level of potential disallowance so as not to discourage the Commission from making appropriate disallowances when the prudency decision is made. Of course, this entails a risk for ratepayers because any undercollection involves potential interest payments to the utilities if the final investment-related disallowance is not great enough to wipe out the amount of interest accumulated on the underpayment. To the extent that individual Commissioners may need the encouragment of an undercollection to make a fair prudency decision, ratepayers might view the risk of paying interest as both necessary and wise. But what may make the risk acceptable to the ratepayer is the possibility of not actually paying the accumulated interest.

In this context, today's decision places $300 million in SCE's basic electricity rates (an equivalent $84m for SDG&E) in order to prevent the current MAAC undercollection of about $357m from snowballing (with interest) to an estimated $700 million by the time we plan to issue our SONGS prudency decision on January 1, 1986. The $300 million increase in electricity rates will still leave an undercollection in the MAAC of about $387 million as of the January 1, 1986 date.

In terms of disallowances in the rate base, a $387 million MAAC undercollection would require investment-related disallowances of approximately $797 million (on a two-year accumulated under-collection basis) in order to wipe out the estimated $387 million undercollection, including accumulated interest. I have not heard anyone in the CPUC argue that a $387 million undercollection wouldn't be a reasonable MAAC undercollection to cover potential investment-related disallowances and at the same time place a reasonable limit on the interest payment exposure of ratepayers.

What has been pointed out, however, is that in addition to investment-related disallowances there may also be some substantial fuel cost disallowances stemming from unreasonable delays in bringing the SONGS units on line. A larger undercollection is needed, according to this view, to cover both potential investment-related disallowances in the rate base and any increased fuel costs attributed to project delays. Since the fuel cost disallowances could be even larger than the investment-related disallowances, a $387 million undercollection might not be considered large enough. This view, therefore, would have us confine the amount to be added to electricity rates at this time to the amount of the decrease in SCE's general rate case to be issued; namely $115.8 million. If we were to limit the adjustment in electricity rates accordingly, the $387 million potential MAAC undercollection would be increased substantially to an estimated $579 million by January 1, 1986. The increased potential undercollection (the difference between a $300 million and a $115.8 million placed in basic electricity rates) would boost the interest payment exposure of ratepayers by about $7.3 million (at present short-term interest rates) solely because there may be a fuel-cost disallowance associated with investment-related disallowances. The increased exposure would be imposed on ratepayers even though only investment-related disallowance can cancel out the interest payment exposure of ratepayers for an undercollection in the MAAC.

The additional $7.3 million increase in ratepayer interest exposure (as a hedge against potential fuel cost disallowances) could not possibly be recovered by ratepayers through any fuel cost disallowances, which would be made through the Energy Cost Adjustment Account (ECAC), unless the amount of investment-related disallowance was artifically increased to cover the added interest rate exposure. It simply would not make much sense to consciously extract such a large amount from ratepayers in order to confront a fuel cost decision. If this were done, the $7.3 million would become an unjustifiable assessment of ratepayers for the purpose of carrying out the Commission's public responsibility. I could not support such an abuse of ratepayers or our public trust, and I don't think it would be anyone's purpose or intent to do so in allowing for a larger undercollection in the MAAC then permitted by this decision. Yet it is important that we understand the full impact of any acceptable level of undercollection when we are dealing with a MAAC that has been established only for investment related purposes.

I believe our decision to allow the additional $300 million in basic electricity rates to be a sound one, quite apart from any risk-sharing issues related to the targeted capacity factor. Regarding the latter, the record is clear that no additional "cap" is needed to limit the exposure of stockholders or to protect the financial security of the utilities beyond the 50/50 sharing of risk of fuel costs outside of the deadband established earlier.

Donald Vial

DONALD VIAL, President

December 28, 1984
San Francisco, California

A.82-02-40
D. 84-12-060

VICTOR CALVO, Commissioner, dissenting in part.

I dissent on three aspects of the Commission's decision in this matter. First, I would have adopted a cap on the penalties and rewards resulting from the target capacity factor (TCF) mechanism. Second, I would have granted rate recognition to something less than the $384 million of SONGS revenues adopted by the majority for the two utilities. Finally, while I wholeheartedly agree with the majority's decision to not adopt the trended rate base (TRB) method of ratemaking for SONGS, I would have been more cautious in assessing its merits relative to other ratemaking options available to us.

The TCF mechanism provides for a sharing of the risk that SONGS will operate inefficiently or irregularly between shareholders and ratepayers. That sharing is appropriate and, as in the past, I endorse it. However, I am concerned that the penalties which might arise from the mechanism would be counterproductive if their imposition resulted in an increased cost of capital which must be borne by ratepayers. To mitigate that possibility, I would adopt a cap on TCF penalties and, to be fair, a cap on TCF rewards.

A cap would have served to reduce the extent of the utilities' exposure to extreme swings in earnings, the most extreme possibly due to broad shut down orders by governmental agencies. The express adoption of a cap would have signalled to investors that this Commission would not permit our utilities to face such uncertainties. Moreover, it is doubtful that the cap would make a material difference in the operation of the TCF mechanism. In the first place, the TCF deadband is expected to capture eighty percent of SONGS operations. Penalties or rewards would therefore be rare. And I do not expect that this Commission would under a worst case scenario, i.e., complete inoperation, resist the pressures to suspend the TCF mechanism. I would therefore have limited TCF penalties such that the penalty would be no greater than 150 basis points in the utilities' post-tax rate of return on equity. Concurrently, I would have adopted a different approach on the AER-TCF mechanism. By limiting the TCF mechanism to ECAC costs only, the majority has eroded the TCF concept far more than would a cap. I strong believe that my approach would have protected both ratepayers and shareholders to a greater extent than does the majority's approach.

As to the matter of present revenues, I believe that a greater uncollected MAAC balance should have been retained. Our cost prudency review is yet to come and the balance left by the majority to offset disallowances does not cover the range of disallowances which some parties have announced that they intend to seek. This raises the spectre of future refunds should we decide on disallowances of any significant magnitude. While the majority apparently believes that it needs no insurance policy against its future timidity, the simple fact is that a refund or rate reduction may result in sizable fluctuations in the companies' earnings records: high for the coming year and low for the next. A lower amount would have avoided this result. Above all, we are told, utility investors seek stabiliy. We should respect that advice.

Further, if the Commission decides on disallowances large enough so that refunds are needed, then we will have required ratepayers to pay rates in the meantime which we later find to be unreasonable. Until the prudency review is complete, I cannot concur in the finding that the adopted SONGS revenue requirements are just and reasonable.

Finally, I believe that the majority decision paints too glowing a picture of the TRB ratemaking proposal. The discussion in the decision does not mention several implementation problems which greatly concern me. For example, accurately determining the appropriate "real" rate of return and asset appreciation rate for the trended rate base amounts would be very difficult and would greatly complicate every general rate case proceeding during the life of the project. The question of whether a regulatory risk premium should be granted, as an increase in either the utilities' overall rate of return or in the "real" rate of return for the trended portion of rate base, would also be a hotly contested issue. Further, most of the other problems with TRB that were cited by the majority as reasons leading to their rejection of TRB for SONGS will still be present if TRB is considered for other utility plant additions.

While I agree that the TRB proposal has many attractive features, satisfactory answers must be found to the many serious questions left unanswered in this proceeding before this Commission should seriously endorse such a radical departure from current ratemaking practices.

As to all other matters resolved in this order, I concur in the opinion of the majority.

Victor Calvo

VICTOR CALVO
Commissioner

December 28, 1984
San Francisco, California

A.82-02-40
D.84-12-060

PRISCILLA C. GREW, Commissioner, Dissenting in part:

I dissent from the majority's decision to put into rates Edison's entire request of $300 million and $84 million for SDG&E. For Edison, I would have held back $150 million in the balancing account as a contingency reserve for the pending prudency proceeding, and I would have reduced SDG&E's award proportionately.

Edison claimed in oral argument (September 13, 1984, page 7668, vol.67) that the projected undercollection in the MAAC balancing account as of the end of 1984 "represents the total capital recovery, including amortization, of nearly 20 percent of Edison's share of the plant investment over a two-year period. The Commission therefore has sufficient flexibility for Phase 2 under our rate proposal."

What Edison failed to point out is that by the anticipated date of the prudency decision, December 1985, the reserve would be less than 20% of the investment, under Edison's model for recovery which substantially reduces reserve accrual during 1985. Furthermore, Edison only mentioned investment-related costs. The Commission has not yet ruled on the issue of whether it might consider fuel cost disallowances in addition to investment-related disallowances in the prudency determination. If the Commission were to find that the onset of plant operation had been unreasonably delayed, it is still conceivable that the Commission might decide on a disallowance of the extra costs of purchased fossil fuel during the period of delay. This contingency has not yet been ruled out by the Commission. As a hypothetical example, a disallowance in December 1985 of 10% of investment-related costs and a year of fossil fuel costs would be about $650 million, much higher than the reserve the majority adopts today. I offer this example as an illustration only, not a suggestion of what eventual Commission action will be.

Since September 7, 1983, the majority has steadily eroded the reserve established to cover potential disallowances in the prudency phase of the San Onofre case.

In Decision 83-09-007, our initial ruling establishing the MAAC balancing account to fully cover accrual of all investment related costs, the Commission followed staff's recommendation to hold the rate authorization to 48% of the annual revenue requirement associated with the costs of SONGS 2.

In Decision 83-11-091, on which I dissented, the majority raised the rate authorization to 70% of the annual revenue requirement. Today the majority accepts Edison's full request to raise rates to cover 92% of investment costs.

I fear that the majority has now given Edison an incentive to delay the prudency review. For the next three years, the majority has granted Edison the highest rate of return of any utility in California for earnings on the San Onofre facility. With rates set at the Edison's full request level of the $300 million increase, and with the plant depreciating, soon the company will be recovering in current rates more than 92% of recovery on the plant investment. With every month of delay in the prudency proceeding, the reserve margin curtailed by today's majority decision will shrink as a proportion of investment costs, because it will have to be spread over a longer period of lower reserve accruals, while the plant continues to earn a high rate of return in the MAAC account. The longer the proceeding is delayed, the lower the proportional reserve the Commission will have to work with. This is not a proper signal to give Edison.

The majority maintains that should unreasonableness be demonstrated, its eventual decision on prudency disallowances will be made independently of the reserve amount available to cover the disallowance.

I applaud this pledge. I sincerely hope that the eventual prudency decision will not be prejudiced by the majority's percentage reduction of the MAAC reserve today.

Priscilla C. Grew
PRISCILLA C. GREW, Commissioner

December 28, 1984
San Francisco, California

A.82-02-40, et al.
D.84-12-060

COMMISSIONER WILLIAM T. BAGLEY, dissenting in part:

It concerns me that our discussion of retroactive ratemaking (PUC Code Section 728) may be taken as a precedent in future cases. I believe that in this instance, if the dollar amount were much larger, then this issue would have been the subject of much more discussion and I believe the result may have been different.

Without lengthy analysis, I do not believe the court would find this Commission constricted by Section 728 under the facts before us. I do not believe that the legislature intended to so tie this Commission's hands in the proper administration of its obligations. The circumstance and sequence here involved do not involve a retroactive change, and this Commission should not so constrict itself if such factual circumstances were to arise in the future. I would adopt the Administrative Law Judge's view as expressed in his proposed decision.

William T. Bagley

WILLIAM T. BAGLEY, Commissioner

December 28, 1984
San Francisco, California